B.C. HYDRO AND POWER AUTHORITY

COGENERATION IN BRITISH COLUMBIA

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"COGENERATION IN BRITISH COLUMBIA"

SUMMARY

TECHNOLOGY

Cogeneration is the sequential production of mechanical or electrical energy and useful thermal energy in the form of steam or hot water from a single energy (fuel) source. It is improved energy efficiency which makes cogeneration environmentally attractive, and in many cases, economic. Cogeneration can improve overall energy efficiency from a range of 15 to 40 percent to a range of 50 to 85 percent depending on the unit size, fuel type and various design features. Much has already been accomplished in improving energy efficiency. Between 1974 and 1984 the pulp and paper industry in B.C. reduced fossil fuel consumption by 36 percent with fuel substitution and increased efficiency.

Energy efficiency has not improved significantly since then because new mills have tended to emphasize improved wood fibre recovery through the use of thermo-mechanical technologies. These technologies require more electricity and less steam thereby reducing the potential for cogeneration.

Cogeneration systems are divided into topping cycles and bottoming cycles depending on the point of extraction of electrical or mechanical energy. Topping cycles generate electricity first and are the most common because relatively low temperatures are usually all that are required for thermal use.

Thermal technologies for cogeneration include conventional thermal, steam engines and gas turbines. Conventional thermal commonly uses coal or wood fuels. The advantages, disadvantages and potential applications for the technologies for thermal power generation are assessed in this report. The theory of cogeneration is also described in order to illustrate the increased efficiency.

Outside the forest industry diesels and gas turbines are more popular for cogeneration than the other thermal technologies. The appropriate prime mover between diesel engines and gas turbines depends on the available fuel, its price and the required thermal/electrical output ratio. Diesel engine and gas turbine cogeneration systems have both industrial and utility applications. Diesel engine cogeneration can have system efficiencies of 40 to 80 percent and very high electricity to steam ratios. Although the cost of diesel fuel is high, some diesel engines can run on natural gas or bunker fuel. Diesel engine unit sizes are restricted to less than 30 MW. Gas turbines have a number of advantages over diesel engines and using a simple cycle with cogeneration can have system efficiencies of 65 to 85 percent, but a lower electricity to steam ratio than diesel engines. Gas turbines can run on premium, high quality liquid fuels or natural gas. Natural gas prices are lower than diesel fuel prices and unit sizes can be as large as 150 MW. Gas turbine combined cycle cogeneration plants (gas turbine combined with a steam turbine) also have system efficiencies of 65 to

85 percent, but a higher electricity to steam ratio than simple cycle gas turbines.

FUELS FOR COGENERATION

Fuels for cogeneration include peat, coal, coke, oil, natural gas, refinery gas, landfill gas, pulping (black) liquors, hog fuel, sewer sludge and municipal solid waste. Hog fuel, an important fuel in the forest industry, consists of wood wastes which are mostly bark, but may contain split logs, slabs, edgings, butts, trim ends, planer shavings, sawdust and/or forest residue from landings, roadsides and non-commercial trees. In addition, trees could be grown specifically for fuel. At present, most of the wood waste is produced at sawmills.

Table 1 summarizes the present use of wood waste and the potential for wood waste utilization. The shortfall in wood waste which is forecast for the Vancouver and Prince Rupert Forest Regions could be made up from other sources. The 150,000 BDT of additional garden wastes scattered at municipal land fills throughout the Lower Mainland would be more than adequate to make up the apparent shortfall for the Vancouver Region. The shortfall in the Prince Rupert Region could be made up partly by hauling from nearby sawmills in the Prince George Region.

Natural gas is particularly popular both as a primary fuel for gas turbines outside the forest industry and as a secondary fuel for power boilers within the forest industry. The popularity is based primarily on its low cost and ease of handling. However, the natural gas price is likely to increase significantly because of increased demand due to the proliferation of gas-fired cogeneration plants as natural gas becomes the fuel of choice to decrease emissions, smog and global temperature increases. Unit sizes for combined cycle plants can be as large as 200 MW. Based on proposals received by B.C. Hydro, over 500 MW of cogeneration and self-generation could be available from new plants or additions to existing diesel and gas turbine plants in B.C.

A recent study completed for B.C. Hydro indicated that the advent of a natural gas supply to Vancouver Island pulp mills may cause natural gas to replace some or all of the hog fuel that these mills now use. Such a shift would result in surplus hog fuel in the Vancouver Forest Region.

INDUSTRIAL APPLICATIONS

The B.C. forest industry accounts for approximately 80 percent of the industrial energy consumption in B.C. and the forest industry is heavily committed to cogeneration. There is approximately 450 MW of cogeneration capacity in the B.C. pulp and paper industry and 27 MW in the wood products industry. Northwest Energy and Howe Sound Pulp and Paper have announced plans to expand wood-fired generation/cogeneration by 140 MW. However, there is still a significant opportunity for additional cogeneration in this industry.

Electrical and thermal energy requirements vary with technology in the pulp and paper industry. For B.C. kraft and sulphite mills the electrical/thermal energy ratio is approximately 0.12. Therefore, in

TABLE 1 - SOURCES OF WOOD WASTE

Forest Region	Mill Waste Residue (BDT)	Mill Waste Surplus (BDT)	Total Surplus (1989) (BDT)[1]	Total Surplus (1995) (BDT)[1]
Vancouver[2]	3,519,500	944,900[3]	1,033,300	-115,100
Prince Rupert	786,500	520,700[4]	520,700	-475,400
Prince George	1,659,300	1,395,700[5]	1,395,700	922,600
Cariboo[6]	1,057,500	897,900[7]	897,900	394,400
Kamloops	1,042,300	622,900[8]	622,900	126,900
Nelson	1,167,600	886,000[9]	886,000	548,300
TOTALS	9,232,700	5,268,100	5,356,500	1,401,700

Footnotes:

1. Includes debris from debris traps as well as a few land sorts and one urban debris site, but does not include wood waste from landings and roadsides.
2. Excludes new, committed generation at Port Mellon (85 MW and 700 GW.h per annum). Approximately 80% of the mill waste surplus in this region is in the Chilliwack Forest District, along the Fraser River.
3. Potential and committed expansions and other self-generation/load displacement projects at Port Mellon, New Westminster, Port Moody, Squamish, Powell River, Nanaimo, Campbell River, Crofton and Gold River would be competing for this surplus wood waste.
4. The surplus is divided among Burns Lake, Hazelton, Smithers and Houston.
5. Approximately 45% of the surplus is in the Prince George District with other significant surpluses at Mackenzie, Vanderhoof and Fort St. James.
6. Wood waste for new, committed generation at Williams Lake and wood waste for the proposed fibreboard plant have been subtracted only from the Total Surplus (1995) column. The new generating plant would have a capacity of 55 MW and annual electricity generation of 438 GW.h.
7. The surplus is divided with approximately 40% each at Quesnel and Williams Lake and the remaining 20% at 100 Mile House.
8. The surplus is divided with approximately 18% each at Clearwater, Vernon, Penticton and Lillooet.
9. The mills are spread over the districts. However, there are significant concentrations at Cranbrook, Skookumchuck, Elko, Creston, Canal Flats, Nakusp and Midway.

the manufacture of pulp and paper, the thermal energy component is much larger than the electrical energy component. For thermo-mechanical pulp the comparable ratio is approximately 0.46 indicating a significantly higher electrical component. For newsprint manufacture the electrical/thermal ratio is in the range of 0.63 to 0.77 which illustrates the energy savings that can be derived from integrating some pulp and paper facilities and maximizing the use of cogeneration.

The potential for electricity generation from wood waste is summarized in Table 2. There are 564 MW of generation under review by the forest industry in B.C. which could generate 4200 GW•h/a assuming full condensing. If all of the wood waste in B.C. was used to generate electricity, generation in the forest industry could increase by 5700 GW.h. Since it seems likely that much of this generation would be developed as cogeneration, the electricity generated could be approximately half of the above estimates.

Other sectors where additional cogeneration could be initiated include the food processing, refinery, chemical and mining industries as well as large institutions. Packaged cogeneration units are becoming more economical and could be used in institutions, offices, smaller buildings and restaurants.

ENVIRONMENTAL IMPACTS

Common to all thermal generation systems, the most significant environmental impact is air emissions. These emissions consist of nitrogen oxides (NO_x), sulphur dioxide (SO_x), carbon dioxide/carbon monoxide, hydrocarbons, trace elements and particulates. The importance of each of the above components depends on the fuel type, fuel source and method of combustion. Of the common fuels, natural gas would have the least environmental impact and it is probable that coal would have the most. In some situations controlled combustion of wood waste in a thermal or cogeneration plant could reduce environmental impacts compared to present methods of incineration or land fill. It should be noted that there are effective methods of controlling the emissions listed above with the exception of carbon dioxide which is believed to be a major contributor to the greenhouse effect. Methods of controlling carbon dioxide emissions are being studied extensively because of recent concern.

CONCLUSIONS

Economic sensitivity analyses were evaluated for this report. The sensitivity analyses for the pulp and paper industry indicated that payback is particularly sensitive to capital cost. There is a distinct advantage from a moderate increase in boiler pressure and temperature above present practice, but little advantage in increasing to high pressure and temperature because capital cost increases disproportionately. At a 5 percent net discount rate only the most capital intensive projects or projects with high fuel prices are uneconomic compared with B.C. Hydro's long-term marginal cost of power.

TABLE 2 - ELECTRICITY GENERATION FROM WOOD WASTE

Forest Region	Present Capacity (MW)	Present Potential Thermal Self-Generation[1] (GW.h)	Proposed Capacity Additions (MW)	Proposed Energy Additions (GW.h)	Total Potential New Capacity (MW)	Total Potential New Energy (GW.h)[2]
Vancouver[3]	257	1915	141	1046	122	708[4]
Prince Rupert	42	310	173	1289	97	621
Prince George	81	600	88	655	242	1801
Cariboo[5]	28	210	20	149	78	580[6]
Kamloops	48	360	84	626	116	865
Nelson	22	165	58	436	154	1148
TOTALS	478	3560	564	4201	809	5723

Footnotes:

1. Assumes an 85% capacity factor. Much of the steam for power generation is derived from recovery boilers at pulp mills. Includes some natural gas and oil-fired generation at pulp mills as well as wood-fired generation at sawmills.

2. Assumes all new generation is condensing. Condensing generation would require approximately half as much fuel as cogeneration for each unit of electricity generation.

3. Excludes new, committed electricity generation at Port Mellon (85 MW and 700 GW.h) per annum. Approximately 80% of the wood waste in this region is in the Chilliwack Forest District, along the Fraser River.

4. Fuel for Port Mellon has been subtracted to arrive at the available energy.

5. Excludes new, committed electricity generation at Williams Lake as well as removal of wood waste for use in the proposed fibreboard plant. The new generating plant will have a capacity of 55 MW and annual electricity generation of 438 GW.h.

6. Fuel for the thermal and fibreboard plants at Williams Lake was subtracted to arrive at the available energy.

Cogeneration methods benefit from reduced fuel costs as a result of increased efficiency and reduced disposal costs. However, financial assistance may be required to improve benefits to pulp mills in order to make a project economic. This may be necessary because of the short payback (less than 3 years) and high rate of return (more than 20 percent) which are imposed by industry on non-product related improvements. These requirements are imposed because of the competitiveness of the national and international market places. Obviously, there is room for negotiation between a utility's marginal cost and the price required by a pulp mill or other cogenerator to meet its economic criteria. The high capital cost and low cost of utility-supplied bulk electricity sales (approximately 30 mills/kW•h) also tend to discourage additional cogeneration.

SECTION 1.0 - INTRODUCTION

1.1 DEFINITION OF COGENERATION

Cogeneration is the sequential production of mechanical or electric energy and useful therm energy in the form of stream or hot water from a single energy (fuel source).[*1] The reject heat from one component of a system is used as the energy source for the next component of the system. Therefore, cogeneration systems can be classified as topping cycles or bottoming cycles. In a topping cycle, electricity or mechanical energy is extracted first and the exhaust stream is delivered as thermal energy or some other form of useful work. In a bottoming cycle, thermal energy is produced for process use and waste heat is recovered for generating electricity. The choice of system is dictated by the balance of thermal energy and electricity which is required and by the quality of the waste heat from the first component of the system.

Another approach to subdividing cogeneration is on the basis of electrical and mechanical[1] energy production. Electrical cogeneration is the sequential production of heat and electricity. Mechanical cogeneration is the sequential production of heat and mechanical work; the latter uses the shaft horsepower from a turbine to drive pumps or compressors instead of an electrical generator. The choice between electrical and mechanical drives depends on factors such as the shaft power-to-thermal energy requirements, reliability considerations, turbine thermodynamic efficiencies and plant layout. In rare cases, mechanical cogeneration can be more efficient than electrical cogeneration because the efficiency loss in transforming shaft power to electric power is eliminated.

1.2 COGENERATION EFFICIENCY

The considerable improvement in overall plant efficiency explains the interest of industry in cogeneration. Conventional thermal generating stations use a condensing steam cycle to achieve overall efficiencies of approximately 15 to 40 percent depending on fuel source, unit size and other design features. Reciprocating engine and gas turbine generation achieve overall efficiencies of 20 to approximately 40 percent depending on unit size and other design features.[2] By contrast cogeneration plants achieve overall efficiencies of 50 to 85 percent depending on the fuel source, unit size, process steam temperature, process steam pressure and other design features of the generating plant.

[*1] A glossary of terms is provided in Appendix A and a summary of equivalent units is listed in Appendix B.

1.3 COGENERATION PROCESSES

Figure 1-1 illustrates numerous processes for cogeneration.[2] These processes can be divided into three stages: primary conversion, secondary conversion and conversion in the prime mover. The working fluid can be steam, fuel gas, hydrogen, hot gas, solid pulverized fuel, liquid fuel or organic vapour.

Despite the numerous alternatives for primary conversion which are illustrated in Figure 1-1, only the steam boiler topping cycle is popular among forest industry cogenerators in British Columbia. Some smaller cogenerators use fuel oil or natural gas in an internal combustion (diesel engine).

1.4 COGENERATION APPLICATIONS

Cogeneration has applications in the industrial, commercial, institutional and residential sectors. However, most of the economic potential for cogeneration is in the industrial sector. B.C. Hydro wants to develop these applications where they are more economical than new, large hydroelectric generation in order to reduce future generation costs. Much of this cogeneration would use wood waste which currently provides a disposal problem for the wood product industry.

There is potential for cogeneration in any industry where there are large continuous steam requirements and significant electricity demands at a high load factor. These industries include pulp and paper, chemicals, steel mills, coal mines, metal smelters, petroleum extraction and refining, gas processing, food processing and textile manufacturing. Cogeneration can also be developed where there is steam or electricity demand by the producer and a potential customer for the sale of surplus steam or electricity.

The forest industry accounts for approximately 80 percent of total industrial energy consumption in B.C. (B.C. Ministry of Energy, Mines and Petroleum Resources, 1980) and the pulp and paper sector accounts for most of this percentage. The pulp and paper sector is strongly committed to cogeneration, but other potential industrial sources of cogenerated power include sawmills, planer mills, plywood and veneer mills and mining companies (particularly off-grid).

Large institutions with significant heating and/or cooling requirements such as hospitals, hotels and universities are also potential cogenerators. Package cogeneration units could be introduced in these institutions as well as schools, offices and other smaller buildings.

1.5 ADVANTAGES OF COGENERATION

There are numerous advantages to using cogeneration. These advantages result from specific siting and economic conditions and can be summarized as follows:

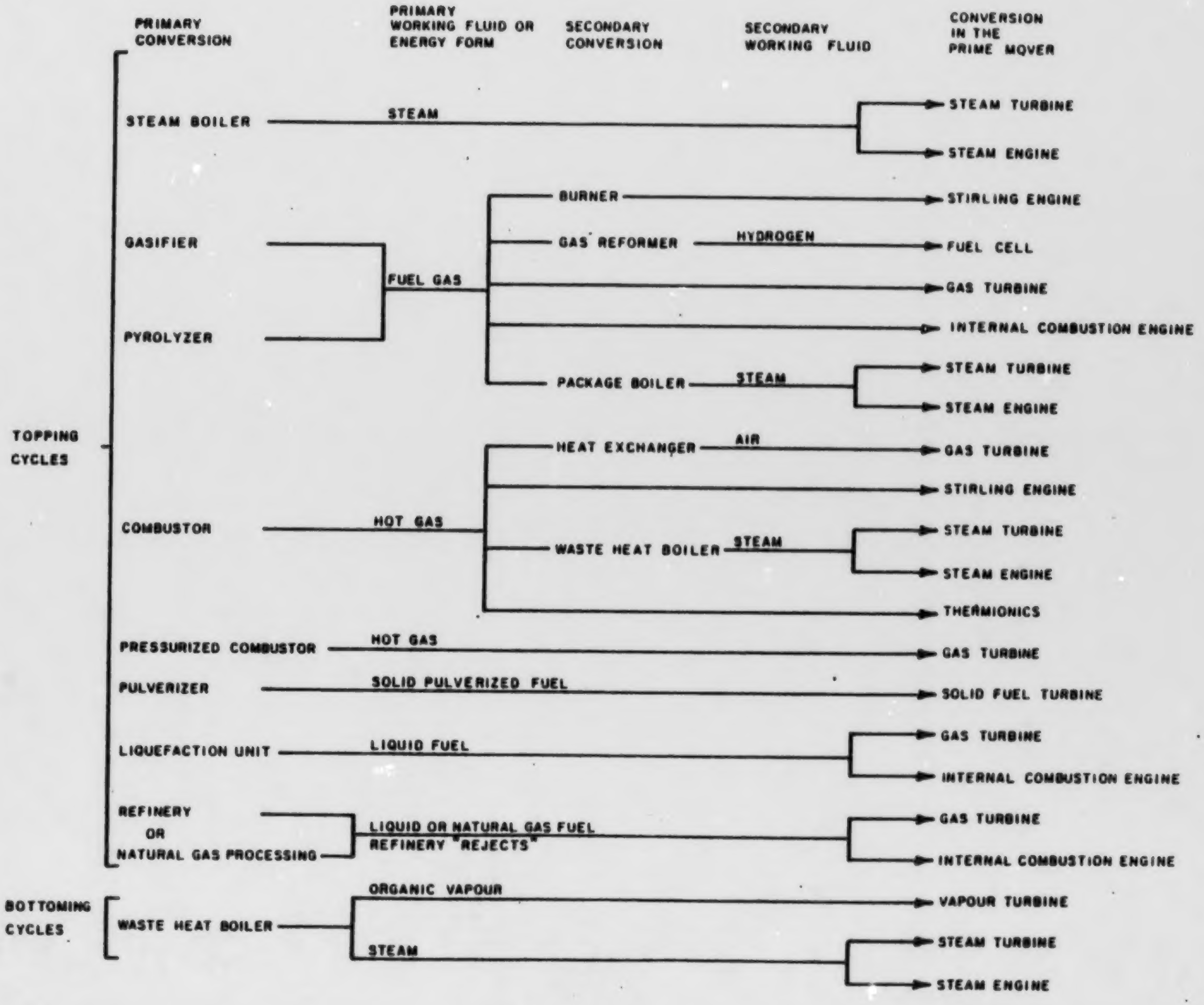

PRIMARY CONVERSION
PRIMARY WORKING FLUID OR ENERGY FORM
SECONDARY CONVERSION
SECONDARY WORKING FLUID
CONVERSION IN THE PRIME MOVER
TOPPING CYCLES
STEAM BOILER
STEAM
STEAM TURBINE
STEAM ENGINE
GASIFIER
PYROLYZER
FUEL GAS
BURNER
STIRLING ENGINE
GAS REFORMER
HYDROGEN
FUEL CELL
GAS TURBINE
INTERNAL COMBUSTION ENGINE
PACKAGE BOILER
STEAM
STEAM TURBINE
STEAM ENGINE
COMBUSTOR
HOT GAS
HEAT EXCHANGER
AIR
GAS TURBINE
STIRLING ENGINE
WASTE HEAT BOILER
STEAM
STEAM TURBINE
STEAM ENGINE
THERMIONICS
PRESSURIZED COMBUSTOR
HOT GAS
GAS TURBINE
PULVERIZER
SOLID PULVERIZED FUEL
SOLID FUEL TURBINE
LIQUEFACTION UNIT
LIQUID FUEL
GAS TURBINE
INTERNAL COMBUSTION ENGINE
REFINERY OR NATURAL GAS PROCESSING
LIQUID OR NATURAL GAS FUEL
REFINERY "REJECTS"
GAS TURBINE
INTERNAL COMBUSTION ENGINE
BOTTOMING CYCLES
WASTE HEAT BOILER
ORGANIC VAPOUR
VAPOUR TURBINE
STEAM
STEAM TURBINE
STEAM ENGINE

Figure I-1

ALTERNATIVE SYSTEM CONFIGURATIONS

1. Commonly lower capital costs for cogeneration than for some alternative electricity generation.
2. Less construction risk for the utility because the risk is borne by the cogenerator.
3. Increased flexibility because of the use of smaller unit sizes and shorter lead times (typically 4 years).
4. Higher fuel efficiency.
5. Reduced transmission losses by siting close to loads.
6. Reduced transmission capital costs.
7. Increased grid stability because of dispersed generating facilities.
8. Greater diversity of fuel sources.
9. Small sizes and unit dispersal which could reduce environmental impacts, unless associated with a large industrial complex which already uses most of the air shed.
10. Improved public relations image.
11. Creates long-term local employment.

Disadvantages of cogeneration include its limited potential for economic development because of the need for a suitable electricity/thermal energy use ratio, the adverse public perception of thermal electrical generation (e.g. smokey, high carbon dioxide emissions, trace elements) and the use of non-renewable fuel sources (e.g. oil, gas) for many developments.

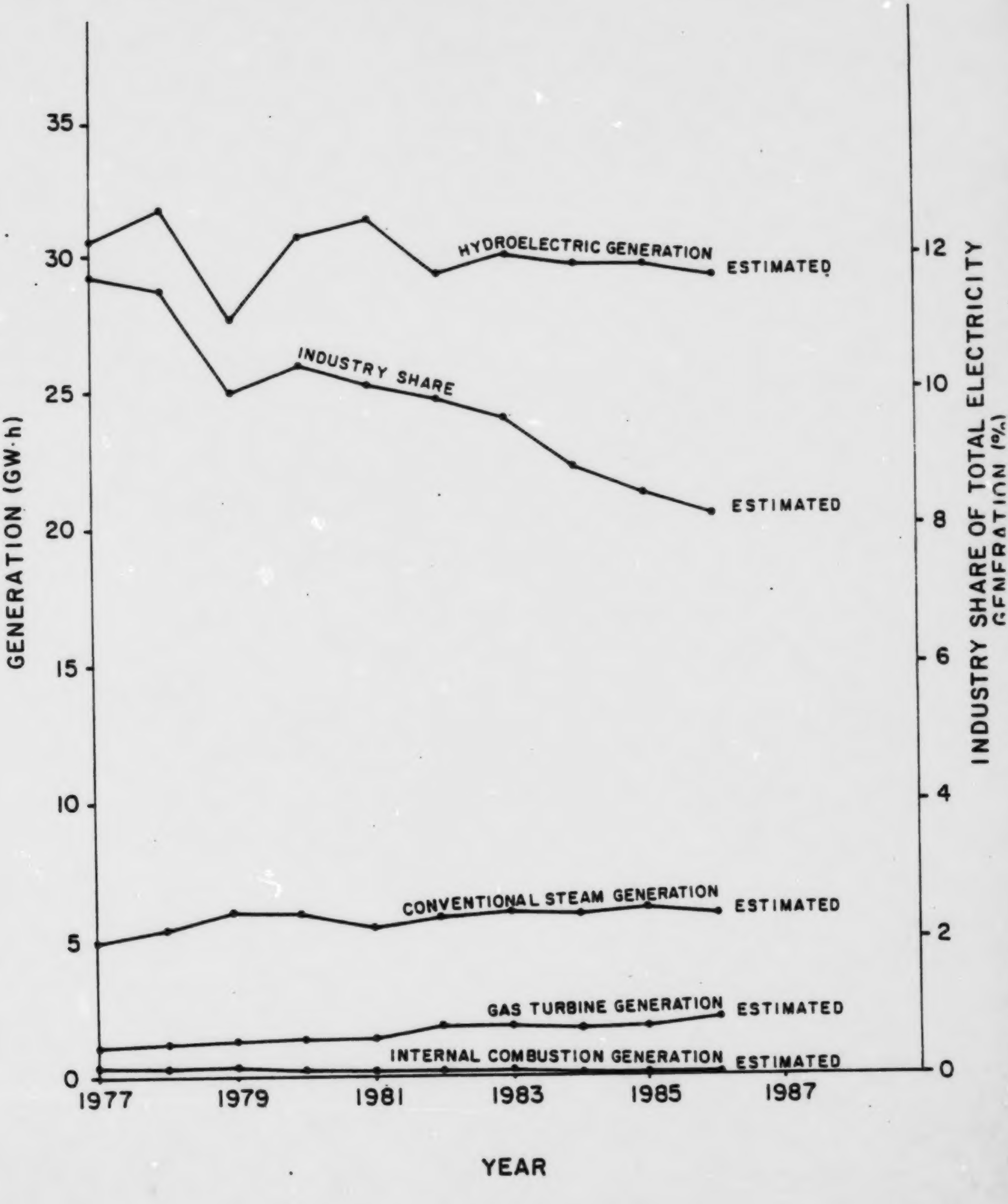
1.6 GROWTH OF INDUSTRIAL GENERATION

Despite the advantages of industrial electricity generation, its growth in Canada was stagnant over the last decade (Figure 1-2).[3] At the same time utilities have captured a larger share of total electricity demand. Industrial electricity generating capacity in British Columbia[*1] is the second highest in Canada and distributed as follows:[4]

	MW
Hydroelectric	1309
Conventional Steam	506
Gas Turbine	0
Internal Combustion	29
TOTAL	1844

Figure 1-2

INDUSTRIAL ELECTRICITY GENERATION IN CANADA FOR COMPANIES WITH AT LEAST ONE PLANT WITH A TOTAL GENERATING CAPACITY EXCEEDING 500 kW



NOTE: [1] For companies with at least one plant with a total generating capacity exceeding 500 kW.

1.7 SELF-GENERATION

Sometimes there is confusion between self-generation and cogeneration. Self-generation of electric power is generation by a power consumer for internal use, possibly with the sale of surplus power to a utility. Unlike cogeneration, process steam is not necessarily produced. Self-generation could be any form of electricity generation including wind, solar, hydroelectric and thermal.

SECTION 2.0 - PURPOSE OF STUDY

Energy resources for meeting the system load in the mid-1990's and beyond has been a concern of the Resource Planning Department. Until that time there is expected to be adequate hydroelectric resources, possibly supplemented by some energy from the Burrard Thermal Plant. From the mid-1990's onward other resources could be required. This study was initiated to identify the energy capability from cogeneration and hog fuel-fired self-generation.

Specifically, this report was initiated to identify the amount of available cogeneration and self-generation, as well as their costs to B.C. Hydro and to summarize the technologies for cogeneration. Factors which affect the availability of cogeneration are also assessed. These factors include the availability of hog fuel and other fuels, the availability of cogeneration without significant plant modification, with steam venting or without steam venting and with additional condensing capability. The cost of energy from each of these alternatives is required in order to assess the amount of cogeneration that could be available economically.

SECTION 3.0 - SCOPE

This study of cogeneration seeks to examine the potential for cogeneration in B.C., particularly from the forest industry, and the availability of this cogeneration to assist B.C. Hydro in meeting electricity demand in the mid-1990's and beyond. Many cogeneration opportunities are expected to be available at lower cost than new, large hydroelectric generation. Cogeneration using wood waste as a fuel is particularly important in B.C. and that prominence is expected to continue. Specifically, the scope of the study is as follows:

1. Identify the surplus cogenerating capacity.
2. Examine the availability of supplementary natural gas.
3. Determine process steam requirements (amounts, temperature and pressure for each use).
4. Determine the electrical requirements of sawmills and pulp mills.
5. Determine the availability of hog fuel and other fuels for cogeneration.
6. Determine the selling prices for the available fuels.
7. Examine the future availability of these fuels.
8. Determine wood waste disposal methods and costs.
9. Conduct sensitivity analyses on the cost of energy available from cogeneration.
10. Examine the potential for using wood waste for other uses than hog fuel firing in a cogeneration plant.

SECTION 4.0 - METHODOLOGY

In order to assess the availability of cogeneration in British Columbia, the following tasks were performed:

1. Discussions were held and information collected from government and forest company agencies (Canadian Forestry Service; Energy, Mines and Resources Canada; B.C. Ministry of Energy, Mines and Petroleum Resources; B.C. Ministry of Environment; Forest Energy Research Institute of Canada; Council of Forest Industries of B.C.).

2. Transmission Supply Marketing contacted some forest companies to determine the availability of cogeneration and their plans for future cogeneration.

3. Literature on past cogeneration studies for B.C.; cogeneration theory; fuel types and characteristics; hog fuel availability and cost; collection methods and costs; chipping methods and costs; drying methods and costs; types of boilers, steam turbines and steam engines; stack gas clean-up; pulp and paper mill operations; diesel prime movers and cogeneration; environmental factors; other uses for steam; and future technologies were examined.

SECTION 5.0 - BACKGROUND FOR HOG FUEL-FIRED THERMAL POWER GENERATION AND COGENERATION IN BRITISH COLUMBIA

Cogeneration was common at industrial sites in the early part of the 20th century, but became less common as isolated industrial sites were integrated into an electric grid and as the cost of electricity from the grid decreased because of the economy of scale available to the larger facilities built by the utility.

B.C. Electric and its successor B.C. Hydro have been interested in hog fuel-fired thermal power generation and cogeneration for some time. In 1959 studies indicated that the installation of a 150 MW hog fuel- fired thermal generating unit at the Burrard Thermal Generating Station was feasible depending on the delivered cost of hog fuel.[5,6] However, B.C. Electric could not get a long-term commitment from the forest industry for a supply of hog fuel. Another report prepared for the B.C. Lumber Manufacturer's Association in 1959 examined the availability of hog fuel for electric power generation.[7]

In 1969 the feasibility of constructing a hog fuel-fired thermal plant was reviewed based on the 1959 study for the Burrard Thermal Generating Station. However, it was concluded that the forest industry was best equipped to handle hog fuel-fired generation.

The low cost of energy in the 1960's and early 1970's, particularly for industries with their own hydroelectric self-generation, continued to discourage the implementation of energy conservation measures including cogeneration. During this period other factors including escalating labour costs, stricter pollution standards, increased competition for world markets and an emphasis on modernization were more important factors affecting production costs.

In 1972 B.C. Hydro investigated the feasibility of a hog fuel-fired thermal generating plant on Vancouver Island.[8] The plant was uneconomical and once again security of a fuel supply was a problem. In the same year International Power and Engineering Consultants (IPEC) compared the costs of hog fuel-fired thermal plants and oil- fired thermal plants and concluded that electricity from the oil-fired plants was more economical.[9]

Energy conservation became an important issue following the oil price shocks of 1973/74 and 1979/80. In 1973/74 B.C. Hydro examined the feasibility of a 600 MW multi-fuelled thermal generating plant on Vancouver Island.[10] The study considered four locations for a plant fired on hog fuel/municipal solid waste and either oil or coal. It was concluded that the multi-fuelled thermal plant would be technically feasible, but it would be more economical to build and operate a plant on coal alone.

In 1974 Kennedy and Donkin Consulting Engineers evaluated an array of combustion techniques and fuels available to B.C. Hydro for thermal power generation.[11] The survey concluded that coal or oil firing, supplemented with wood or municipal solid waste was technically feasible, but conversion of the Burrard Thermal Plant boilers for coal firing through either gasification of fluidized bed combustion was not economical at that time.

In 1974 Reid, Collins and Associates investigated the long-term availability of hog fuel for thermal power generation in British Columbia.[12] Substantial long-term surpluses were identified in the B.C. Interior. However, only short-term surpluses were identified on the South Coast.

Also in 1974, H. A. Simons examined the electricity consumption, generation and purchase by the B.C. forest industry.[13] It was found that most mills had surplus steam generating capacity because they passed their steam through pressure reducing valves to process use. This energy, which is otherwise wasted, could be converted to electric power through the use of non-condensing topping steam turbo-generators. Power costs from B.C. Hydro were sufficiently low to provide no incentive for this additional in-house generation.

In May 1977, the Wood Waste Coordinating Committee was established by the B.C. Energy Commission to examine methods of using surplus wood waste produced by the forest industry. The committee examined hog fuel availability and hog fuel cogeneration at Quesnel.

In 1977, H. A. Simons examined the physical, technical, financial and environmental constraints to full utilization of hog fuel from the Quesnel area.[14] The study recommended construction of a cogeneration plant to use the surplus hog fuel.

In 1978, B. H. Levelton and Associates evaluated wood waste energy conversion systems to replace fossil fuel used in the forest industry.[15] The study examined suspension burners, fluid-bed combustors, multiple chamber combustors, single chamber combustors, packaged power boilers, gasification, pyrolysis and wood densification (pelletizing), but excluded conventional hog fuel boilers. It was concluded that full commercial development of these alternate energy conversion systems was not feasible, but commercial scale development of some of these technologies would occur in the near future.

In January 1978, Reid, Collins and Associates estimated the availability of hog fuel throughout B.C.[16] Significant surplus hog fuel for cogeneration was noted at Williams Lake, Quesnel, Prince George and Mackenzie. Quesnel was selected as the most feasible site for cogeneration because of the concentration of sawmills at the Two Mile Flat industrial site.

In September 1978, Reid Collins and Associates completed a separate study on the availability of hog fuel over the South Coast region of British Columbia.[17] It was determined that some surplus hog fuel was available on the South Coast, particularly in the Fraser River delta.

In September 1979, Sandwell completed a study for B.C. Hydro on the engineering and economics of a single, hog fuel-fired, 60 MW, travelling grate, thermal generating plant at Quesnel.[18] Provision was made for adding a second 60 MW unit. Supplemental fuelling by municipal waste, alternate fuelling by oil or gas and future fuelling by conversion to coal were included in the boiler design. Substitution of an extraction-condensing turbine would permit the sale of steam for kiln heating. The economic evaluation assumed a 3-year construction period and an economic life of 20 years. No allowance was made for government assisted financing or for the elimination of the present wood waste disposal costs. Revenues, operating costs and capital costs were escalated at 6.5 percent for 1984 and at 6 percent per annum thereafter. The proposed Quesnel hog fuel-fired thermal generating plant was deemed to be technically feasible, but not economical relative to alternative hydro and coal-fired thermal power generation. In addition, there was no guaranteed wood waste supply for the plant.

In February 1980, Integ completed a study on cogeneration in British Columbia for B.C. Hydro and the B.C. Energy Commission.[19] The study was based on a survey of 30 forest and 16 non-forest industry operations. Several methods for increasing cogeneration were investigated. The study concluded that between 60 and 70 MW of cogeneration could be developed technically and economically. Increased cogeneration in the non-forest industries, based on oil and natural gas was found to be uneconomic. Some of the constraints against development of hog fuel-fired cogeneration were identified in the Integ (1980) study and included the following:

1. The large capital investment and the high rate of return required by the forest industry.

2. The present low cost of electricity to industrial customers on the B.C. Hydro main grid.

3. The lack of a secure source of supply for hog fuel and the variable quality of available supplies.

In June 1980, Sandwell and B.C. Hydro updated the study on availability of hog fuel for a Quesnel thermal generating plant.[20] This survey of hog fuel availability indicated that long-term timber supply and allowable timber cuts would be 267000 GPU/a. Approximately 350000 GPU/a would be required for a 60 MW plant at Quesnel. Therefore, a firm contract would be necessary before a wood-fired thermal plant could be built at Quesnel.

From 1981 onward, additional reports on the availability of forest wood residue, methods of recovering and processing this residue were prepared for FERIC (Forest Engineering Research Institute) and the Canadian Forestry Service. The conclusions from these reports are described in the appropriate sections of this report.

SECTION 6.0 - FUELS FOR COGENERATION

6.1 INTRODUCTION

Fuels for cogeneration include peat, coal, coke, oil, natural gas, refinery gas, landfill gas, pulping (black) liquors, hog fuel, sewer sludge and municipal solid waste (MSW). The hog fuel consists mostly of bark but may contain split logs, slabs, edgings, butts, trim ends, planer shavings, sawdust and/or forest residue from landings, roadsides and non-commercial trees. In addition, trees may be grown on tree farms specifically for fuel. Logging residue and wood from tree farms are seldom used because of the added cost. Planer shavings and sawdust are often used as a pulp furnishes. Therefore, they may not be available for hog fuel.

Older Coastal B.C. wood product mills have hog fuel-fired power boilers, whereas newer Interior B.C. mills rely on natural gas for process heat, mainly for lumber and veneer drying kilns.[6] New mills, both in the Interior and on the Coast are installing wood-fired power boilers for steam heat because of the problem of disposing of wood wastes. The present disposal methods include beehive burners and landfills.

Pulp mills in B.C. commonly have recovery boilers fuelled with pulping liquor and hog fuel-fired boilers which use supplementary oil or natural gas. Oil and natural gas were popular fuels because of their availability, the small boiler size and their ease of handling. However, oil, has become less popular since 1973 because of price volatility.

Peat is not a popular fuel because of its high water content, the remoteness of fuel sources, low heating value, high cost of recovery and high transportation cost per unit of energy.

These fuels are each described briefly in this chapter.

6.2 FUELS AND ELECTRICITY GENERATION FOR NEW COGENERATION PLANTS IN THE UNITED STATES

A list of the cogeneration plants under construction in the United States in October 1986 is summarized in Table 6-1 and Fig. 6-1.[21] The unit sizes range from 1 to 150 MW. The types of fuel cover a broad spectrum of fossil and renewable fuels. However, over 60 percent of the new generation will be from natural gas or coal. It is estimated that approximately 72 percent of the new cogeneration will be from predominantly fossil fuels. The largest renewable contributor to new cogeneration will be MSW at 10.3 percent. The important implication of this new cogeneration for B.C. and the rest of Canada is the future availability of natural gas or, more accurately, the future price of natural gas because of the increase in demand.

TABLE 6-1

COGENERATION PLANTS UNDER CONSTRUCTION IN THE UNITED STATES

State	No. of Units	Size Range (MW)	Total New Capacity (MW)	Fuel
Alaska	1	-*[1]	10.0	coal
Alabama	1	-	13.5	coke oven gas
Arizona	1	-	5.0	natural gas
California	7	10-17	108.0	coke
	3	44-49.9	143.4	coal-coke
	15	15-49.9	492.5	coal
	1	-	26.5	coal-wood
	1	-	1.4	coal-sewage sludge-MSW
	11	10-54.9	272.6	wood
	9	7.3-60.0	205.2	biomass
	2	10-26	36.0	sewage sludge
	4	25-46	149.0	MSW
	1	-	25.0	sewage sludge - digester gas
	1	-	54.0	MSW-natural gas
	5	2-40	56.2	landfill gas
	2	25-90	115.0	refinery gas-natural gas
	1	-	49.0	natural gas-oil
	2	6-49	55.0	oil
	41*[2]	1.5-120	1222.4	natural gas
Colorado	1	-	75.0	natural gas
Connecticut	1	-	60.0	biomass
	1	-	16.0	MSW
	1	-	68.0	MSW-coal
	1	-	11.0	wood
	2	52-78	130.0	natural gas-oil
Florida	1*[3]		60.0	biomass
	3	12.5-50	91.5	MSW
	1	-	152.0	coal
	1	-	5	digester gas
	1	-	25.7	natural gas
Hawaii	1	-	57.0	MSW
Illinois	2	62-150	212.0	coal
	3	1-8	16.5	natural gas
Indiana	1*[4]	-	4.0	coal
Iowa	3	8-120	167.0	coal
	1	-	3.0	natural gas-oil
Louisiana	1	-	110.0	natural gas
Maine	2	15-16	31.0	biomass
	2*[3]	24.8	49.6	wood
	2	14-21	35.0	MSW

TABLE 6-1 (Cont'd)

State	No. of Units	Size Range (MW)	Total New Capacity (MW)	Fuel
Massachusetts	2	15-30	45.0	coal
	1	-	50.0	biomass
	1	-	32.0	MSW
	1	-	27.0	natural gas
Michigan	2	16.2	32.4	wood
	1	-	65.0	MSW
	1*[5]	-	26.0	coal
	2	4-6	10.0	natural gas
Minnesota	2	25	50.0	MSW
	1	-	6.0	coal
Missouri	1	-	19.5	coal
Montana	1	-	30.0	coal
Nebraska	1	-	8.0	coal
New Hampshire	2	14-15	29.0	biomass
	1	-	5.0	MSW
New Jersey	3*[4]	12.5-67	104.5	MSW
	2	12-25	37.0	natural gas
New Mexico	1	-	2.3	digester gas
New York	1	-	80.0	biomass
	3	10-14	36.5	MSW
North Carolina	1*[5]	-	20.0	coal
North Dakota	1	-	13.3	coal
Oklahoma	1*[4]	-	16.5	MSW
Oregon	1	-	13.1	MSW
Pennsylvania	6	34.5-128	425.0	coal-coal rejects
	2	16.2-35	51.2	wood
	1	-	8.0	MSW
	2	12.6-35	36.9	natural gas
	1	-	3.7	natural gas-oil
South Carolina	1	-	16.0	MSW
	1	-	72.0	wood
Texas	1	-	20.0	biomass
	1	-	135.0	coke-coal
	8*[6]	12.1-430	983.8	natural gas
Vermont	1	-	5.0	MSW
Virginia	1	-	20.0	MSW
	1	-	27.2	coal
West Virginia	-*[5]	-	-	coal
Wyoming	1	-	18.8	natural gas

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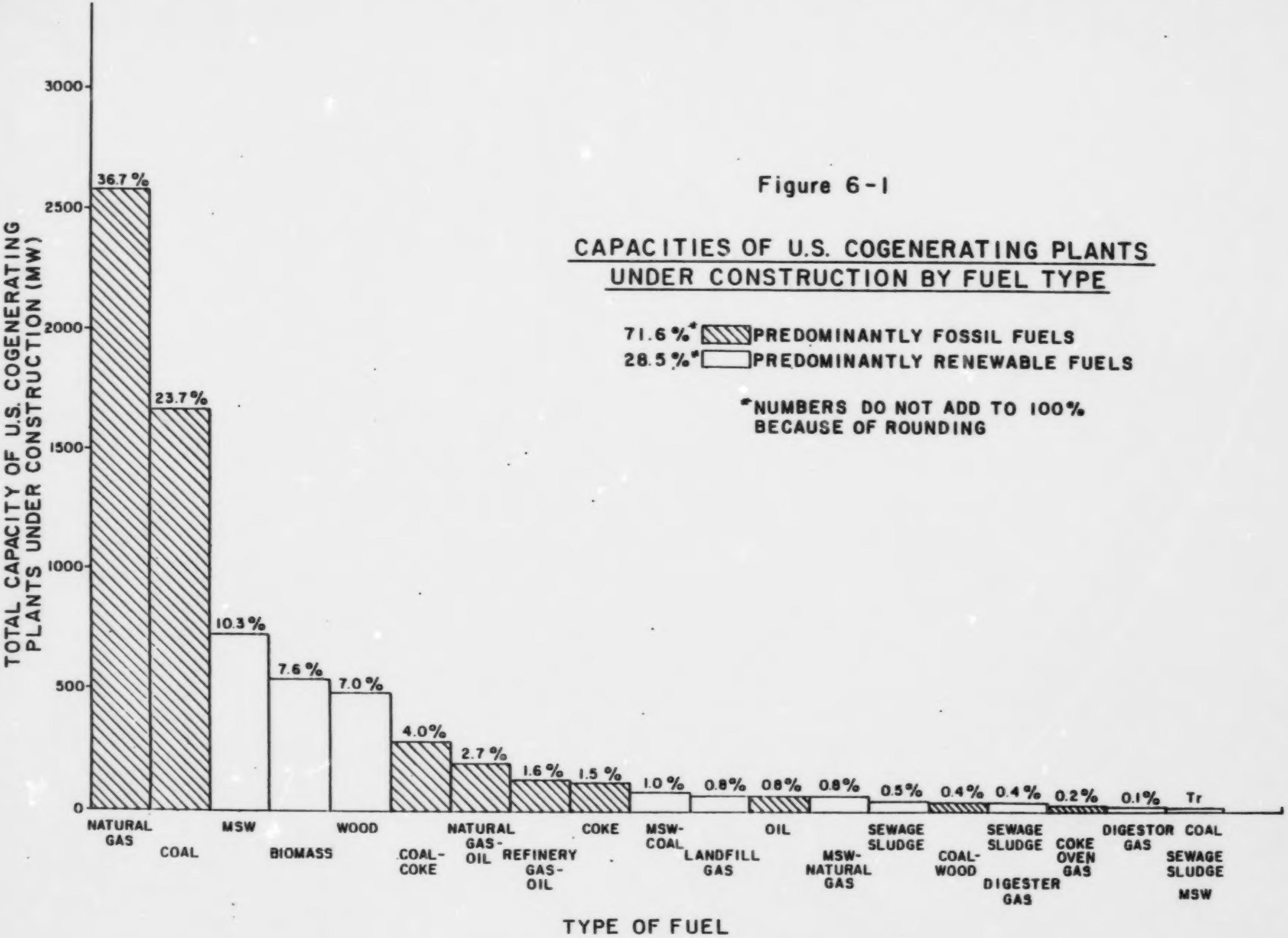
*[1] Indicates information is unavailable.
*[2] Seven natural gas-fired units of unknown size are not included.
*[3] One wood-fired unit of unknown size is not included.
*[4] One MSW-fired unit of unknown size is not included.
*[5] The unit is coal-fired but the size is unknown.
*[6] One natural gas-fired unit of unknown size is not included.

Figure 6-1

CAPACITIES OF U.S. COGENERATING PLANTS UNDER CONSTRUCTION BY FUEL TYPE



6.3 FUELS, ELECTRICITY GENERATION AND ENERGY CONSERVATION IN CANADIAN PULP AND NEWSPRINT MILLS

Tables 6-2 and 6-3 and Figs. 6-2 to 6-5 summarize the distribution of fuel types for a cross-Canada sample of 15 bleached kraft pulp mills and 19 integrated suphite pulp/newsprint mills over the period 1972 to 1984.[22] In the kraft pulp mills, the use of local pulp liquors and hog fuel has increased over time at the expense of the fossil fuels, residual oil and natural gas. Similarly, for the integrated suphite pulp/newsprint mills, the use of purchased electricity and hog fuel has increased at the expense of residual oil, natural gas, coal and coke. These trends are expected to continue.

In general, the purchased energy use per unit of product for pulp and paper mills decreased by 27 percent between 1972 and 1984 (Table 6-4).[22] The decrease in the use of purchased energy is due principally to the substitution of hog fuel and pulp liquors.

The distribution of energy sources for integrated suphite pulp/newsprint mills across Canada are summarized in Table 6-5.[22] Total energy use per unit of product decreased between 1972 and 1984 and the decrease in residual oil is the most significant. Electricity increased slightly, particularly with the substitution of some electric boilers for residual fuel oil boilers in Quebec.

Between 1976 and 1980 the Canadian pulp and paper industry reduced its fossil fuel consumption by 17.2 percent and by a further 30 percent by 1985.[23] These energy savings were achieved in two ways:

1. By modifying processes through machinery replacement, operational changes and energy management in order to use less energy per unit of production.

2. By substituting hog fuel, spent pulping liquors and self-generated electricity for fossil fuels.

Hog fuel is used in pulp mills as an important fuel source. Some constraints to greater utilization of hog fuel include the occasional influx of very wet hog fuel, foreign material in the hog fuel, fly ash removal problems, limitations in hog fuel handling and problems with boiler operation. Insufficient supply, cost and insufficient storage capacity were not cited by pulp mills as constraints on the use of hog fuel.

A survey of 16 pulp and paper mills in B.C. concluded that between 1974 and 1984 electricity consumption per unit of product increased by 14 percent and in the corresponding period the use of hog fuel increased by 36 percent (Fig. 6-6).[23] These increases were at the expense of oil and natural gas; their use decreased by 35 percent over the same period. However, the overall use of energy per unit of product decreased by only 3.2 percent between

TABLE 6-2
BLEACHED KRAFT PULP MILL SAMPLE ENERGY CONSUMPTION BY FUEL TYPE*[1]
(input energy units)

	Purchased Electricity			Natural Gas			Residual Fuel Oil			Distillates & LPGs			Coal, Coke, and Other		
	PJ	Growth Rate*[2] (%)	Share*[3] (%)	PJ	Growth Rate (%)	Share (%)	PJ	Growth Rate (%)	Share (%)	PJ	Growth Rate (%)	Share (%)	PJ	Growth Rate (%)	Share (%)
1972	3.7		3.0	16.2		13.2	16.7		13.6	0.6		0.5	2.6		2.1
1976	4.2	14.2	3.1	19.1	17.7	14.0	15.0	(10.3)	11.0	0.6	(3.1)	0.5	2.0	(24.4)	1.4
1977	4.2	(2.1)*[4]	3.1	17.6	(8.0)	13.2	11.7	(22.2)	8.7	0.7	16.5	0.5	2.2	12.9	1.7
1978	4.4	4.7	3.0	19.0	8.0	12.9	12.3	5.4	8.4	0.6	(13.4)	0.4	2.2	1.2	1.5
1979	4.5	4.5	3.2	19.2	1.2	13.5	12.9	5.1	9.1	0.8	19.8	0.5	1.9	(14.3)	1.4
1980	4.5	(1.4)	3.1	21.3	10.8	14.6	11.5	(11.1)	7.9	0.7	(9.5)	0.5	2.1	7.6	1.4
1981	4.1	(7.9)	3.2	17.8	(16.4)	13.6	10.7	(6.5)	8.2	0.8	15.5	0.6	2.1	1.2	1.6
1982	3.8	(7.5)	3.0	17.0	(4.2)	13.5	9.3	(12.9)	7.4	0.6	(25.3)	0.5	1.8	(13.3)	1.4
1983	3.8	0.0	2.9	15.3	(10.2)	11.8	8.3	(10.9)	6.4	0.4	(26.7)	0.3	2.0	9.8	1.5
1984	4.3	12.0	3.4	14.3	(6.5)	11.2	8.4	0.7	6.6	0.5	5.1	0.4	2.2	8.5	1.7

	Hog Fuel			Pulping Liquors			Self-Generated Hydraulic Power			Total Energy	
	PJ	Growth Rate (%)	Share (%)	PJ	Growth Rate (%)	Share (%)	PJ	Growth Rate (%)	Share (%)	PJ	Growth Rate (%)
1972	15.0		12.1	68.2		55.3	0.3		0.3	123.4	
1976	22.6	51.1	16.6	72.1	5.6	52.8	0.9	180.9	0.6	136.5	10.6
1977	23.7	5.1	17.8	73.0	1.4	54.8	0.3	(70.7)	0.2	133.4	(2.3)
1978	27.1	14.2	18.5	81.0	10.9	55.1	0.3	16.1	0.2	146.9	10.1
1979	25.4	(6.3)	17.8	77.4	(4.4)	54.4	0.2	(29.2)	0.2	142.4	(3.1)
1980	23.8	(6.3)	16.3	82.2	6.1	56.2	0.2	(5.1)	0.1	146.2	2.7
1981	20.6	(13.5)	15.8	74.4	(9.4)	56.9	0.2	4.0	0.2	130.8	(10.6)
1982	23.0	11.7	18.2	70.4	(5.4)	55.8	0.2	0.9	0.2	126.2	(3.5)
1983	26.4	14.6	20.4	73.2	4.0	56.5	0.2	(4.0)	0.2	129.7	2.7
1984	23.6	(10.7)	18.5	73.6	0.5	57.8	0.5	124.4	0.4	127.2	(2.0)

---

*[1] Sample of 15 mills out of 25 in the Canadian Pulp and Paper Association product group.
*[2] Growth rate in energy (PJ) from previous year.
*[3] Energy (PJ) of fuel type as percentage of Total Energy.
*[4] Numbers in brackets are negative growth rates.

TABLE 6-3
INTEGRATED SULPHITE PULP/NEWSPRINT MILL SAMPLE - ENERGY CONSUMPTION BY FUEL TYPE*[1]
(input energy units)

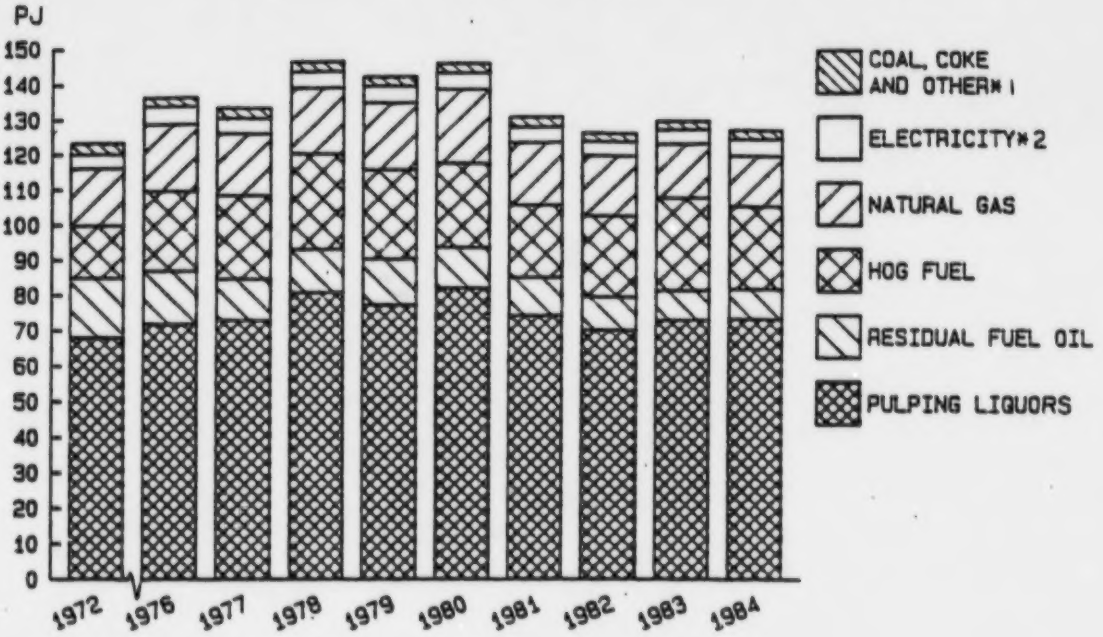
	Purchased Electricity			Natural Gas			Residual Fuel Oil			Distillates & LPGs			Coal, Coke, and Other		
	PJ	Growth Rate*[2] (%)	Share*[3] (%)	PJ	Growth Rate (%)	Share (%)	PJ	Growth Rate (%)	Share (%)	PJ	Growth Rate (%)	Share (%)	PJ	Growth Rate (%)	Share (%)
1972	29.6		34.7	10.5		12.3	28.2		33.0	2.0		2.3	5.6		6.6
1976	32.1	8.2	39.6	12.5	18.4	15.4	21.1	(25.3)	26.0	1.8	(11.2)	2.2	5.1	(8.9)	6.3
1977	33.6	4.7	40.5	11.2	(10.6)	13.5	21.2	0.7	25.6	1.8	2.7	2.2	4.5	(12.3)	5.4
1978	34.5	2.8	38.4	12.4	11.5	13.8	22.6	6.5	25.1	2.2	19.4	2.4	5.3	17.4	5.9
1979	33.5	(3.1)*[4]	37.4	12.1	(2.4)	13.6	22.0	0.0	24.7	2.4	12.1	2.7	4.5	(15.4)	5.0
1980	33.9	1.3	38.5	11.3	(6.7)	12.9	22.3	1.2	25.3	2.3	(6.1)	2.6	3.7	(16.2)	4.2
1981	35.7	5.2	40.1	10.2	(10.1)	11.4	22.8	2.2	25.6	2.3	0.0	2.6	2.6	(29.5)	3.0
1982	32.6	(8.7)	40.8	8.6	(14.8)	10.9	20.9	(8.1)	26.2	1.8	(20.3)	2.3	2.3	(14.2)	2.8
1983	34.8	6.8	43.1	7.7	(10.8)	9.6	16.9	(19.1)	21.0	1.7	(7.1)	2.1	3.3	44.5	4.0
1984	39.9	14.7	46.1	9.7	25.1	11.2	13.0	(23.4)	15.0	1.7	3.1	2.0	3.2	(1.5)	3.7

	Hog Fuel			Pulping Liquors			Self-Generated Hydraulic Power			Total Energy	
	PJ	Growth Rate (%)	Share (%)	PJ	Growth Rate (%)	Share (%)	PJ	Growth Rate (%)	Share (%)	PJ	Growth Rate (%)
1972	5.3		6.2	0.6		0.7	3.6		4.2	85.5	
1976	5.1	(4.5)	6.2	0.3	(43.3)	0.5	3.1	(14.4)	3.8	81.0	(5.3)
1977	5.7	13.2	6.9	0.7	110.9	0.9	4.2	35.8	5.0	82.9	2.4
1978	7.9	38.7	8.8	0.8	9.0	0.9	4.2	1.5	4.7	90.0	8.5
1979	8.8	10.8	9.8	0.8	7.5	0.9	5.1	22.7	5.8	89.3	(0.7)
1980	8.7	(1.0)	9.9	0.8	(3.0)	0.9	5.1	(2.3)	5.8	88.1	(1.4)
1981	10.0	14.5	11.2	0.5	(43.7)	0.5	5.0	(1.5)	5.6	89.0	1.0
1982	9.0	(9.7)	11.3	0.3	(39.1)	0.3	4.3	(13.5)	5.4	79.8	(10.3)
1983	11.0	22.2	13.6	0.9	231.9	1.1	4.4	2.5	5.5	80.7	1.1
1984	14.1	28.5	16.3	0.9	(1.2)	1.0	4.0	(8.8)	4.7	86.5	7.2

*[1] Sample of 18 mills out of 26 in the Canadian Pulp and Paper Association product group.
*[2] Growth rate in energy (PJ) from previous year.
*[3] Energy (PJ) of fuel type as percentage of Total Energy.
*[4] Numbers in brackets are negative growth rates.

Figure 6 - 2

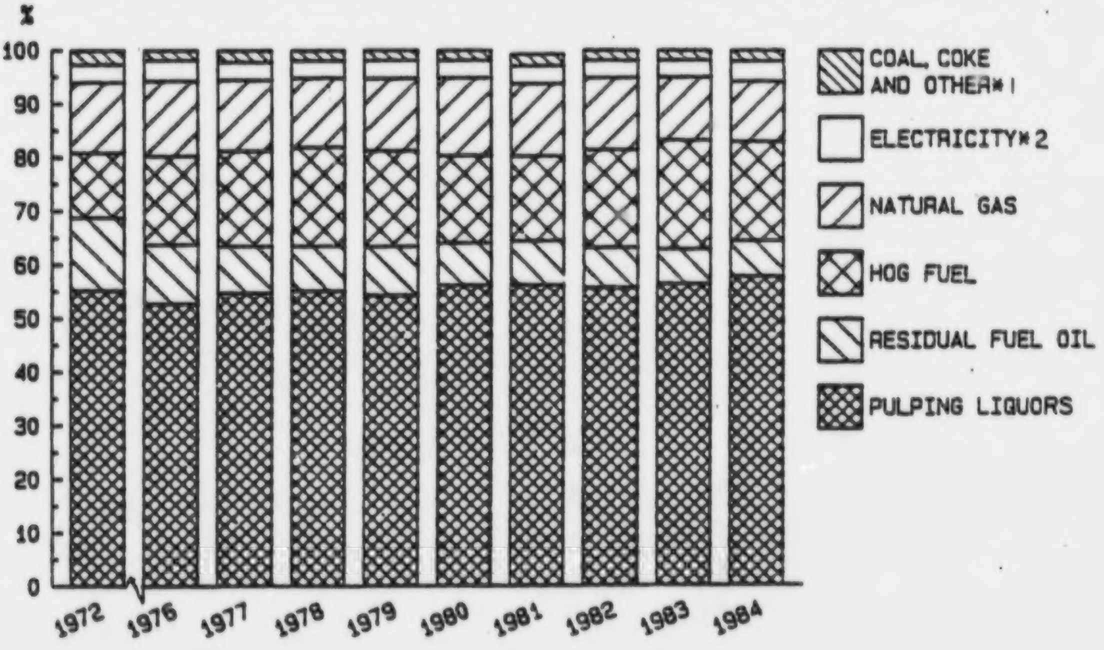
SAMPLE OF BLEACHED KRAFT PULP MILLS ENERGY CONSUMPTION BY FUEL TYPE



*1 INCLUDES DISTILLATES, LIQUID PETROLEUM GAS AND STEAM
*2 INCLUDES PURCHASED AND SELF-GENERATED HYDRO

Figure 6 - 3

SAMPLE OF BLEACHED KRAFT PULP MILLS SHARES OF ENERGY CONSUMPTION BY FUEL TYPE



*1 INCLUDES DISTILLATES, LIQUID PETROLEUM GAS AND STEAM
*2 INCLUDES PURCHASED AND SELF-GENERATED HYDRO. THE 1984 INCREASE IS CAUSED BY HYDRO QUEBEC'S INDUSTRIAL BOILER CONVERSION PROGRAM.

Figure 6 - 4

SAMPLE OF INTEGRATED SULPHITE PULP/NEWSPRINT MILLS ENERGY CONSUMPTION BY FUEL TYPE

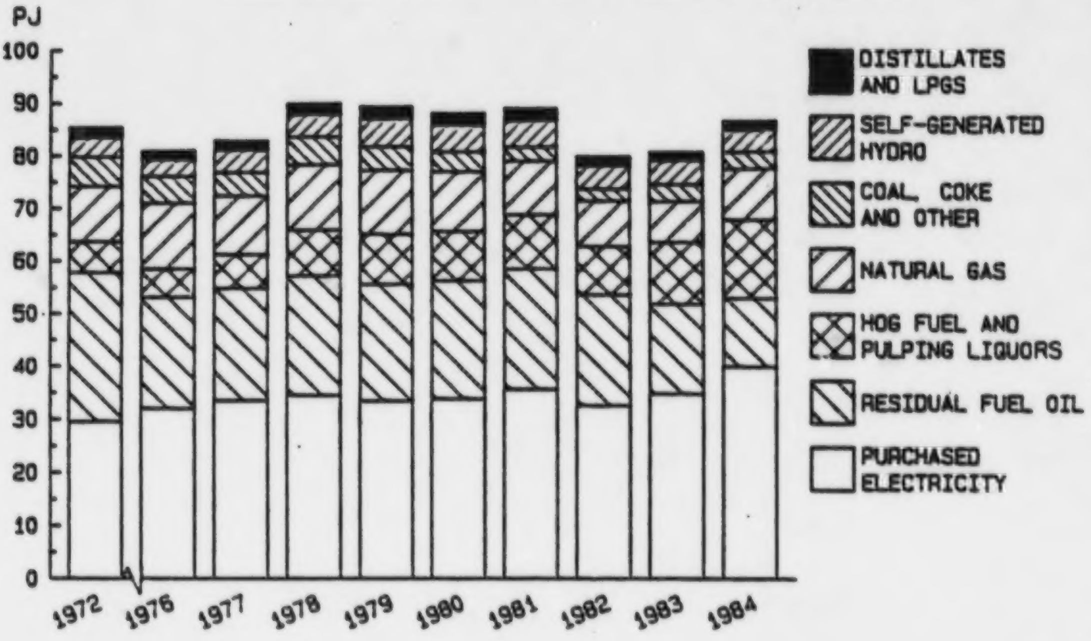


Figure 6 - 5

SAMPLE OF INTEGRATED SULPHITE PULP/NEWSPRINT MILLS SHARES OF ENERGY CONSUMPTION BY FUEL TYPE

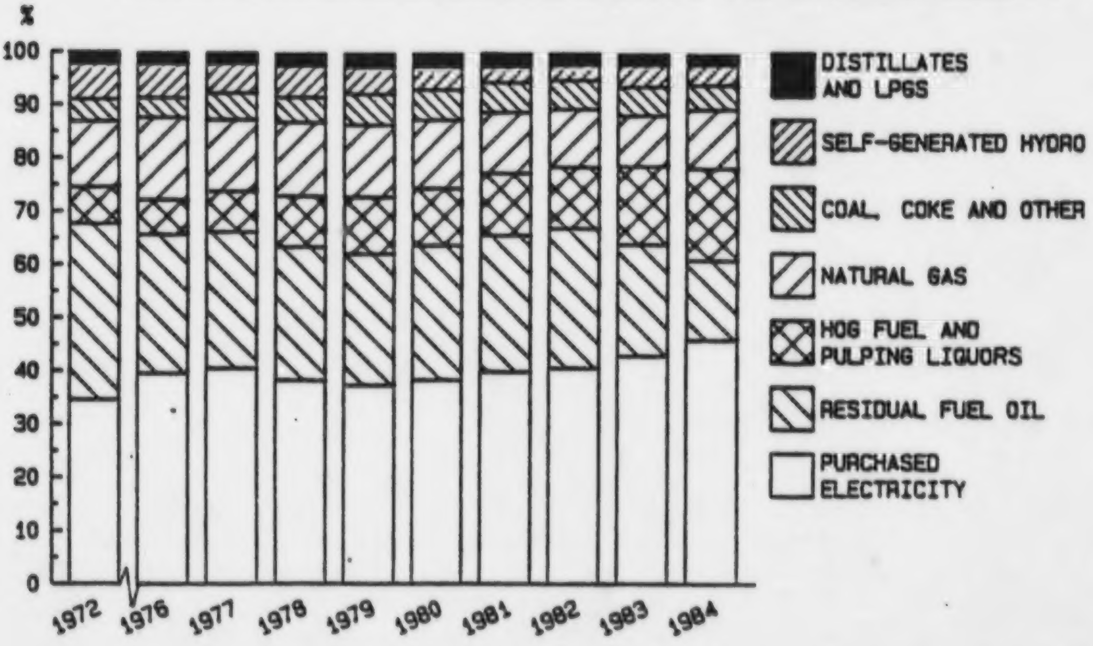


TABLE 6-4

PURCHASED ENERGY USE - CANADIAN PULP AND PAPER ASSOCIATION SURVEY OF PULP AND PAPER MILLS

(GJ/t of product)

	Electricity	Heavy Fuel Oil	Distillates	Natural Gas	Coal	Other*[1]	Total
1972	4.5	9.0	0.3	3.8	0.7	0.2	18.5
1977	4.7	7.4	0.4	4.2	0.6	0.3	17.8
1978	4.7	7.0	0.3	3.9	0.6	0.2	16.7
1979	4.4	6.5	0.4	4.0	0.5	0.1	15.9
1980	4.5	6.0	0.4	3.9	0.5	0.2	15.5
1981	4.8	5.9	0.3	3.9	0.4	0.2	15.5
1982	5.0	5.6	0.3	4.0	0.5	0.2	15.6
1983	5.0	4.5	0.2	3.5	0.5	0.1	13.8
1984	5.7	3.6	0.3	3.5	0.4	0.0	13.5

*[1] Purchased steam and propane.

TABLE 6-5

INTENSITY OF ENERGY USE BASED ON SELECTED FUELS AND THE TOTAL ENERGY FOR A SAMPLE OF INTEGRATED SULPHITE PULP/NEWSPRINT MILLS

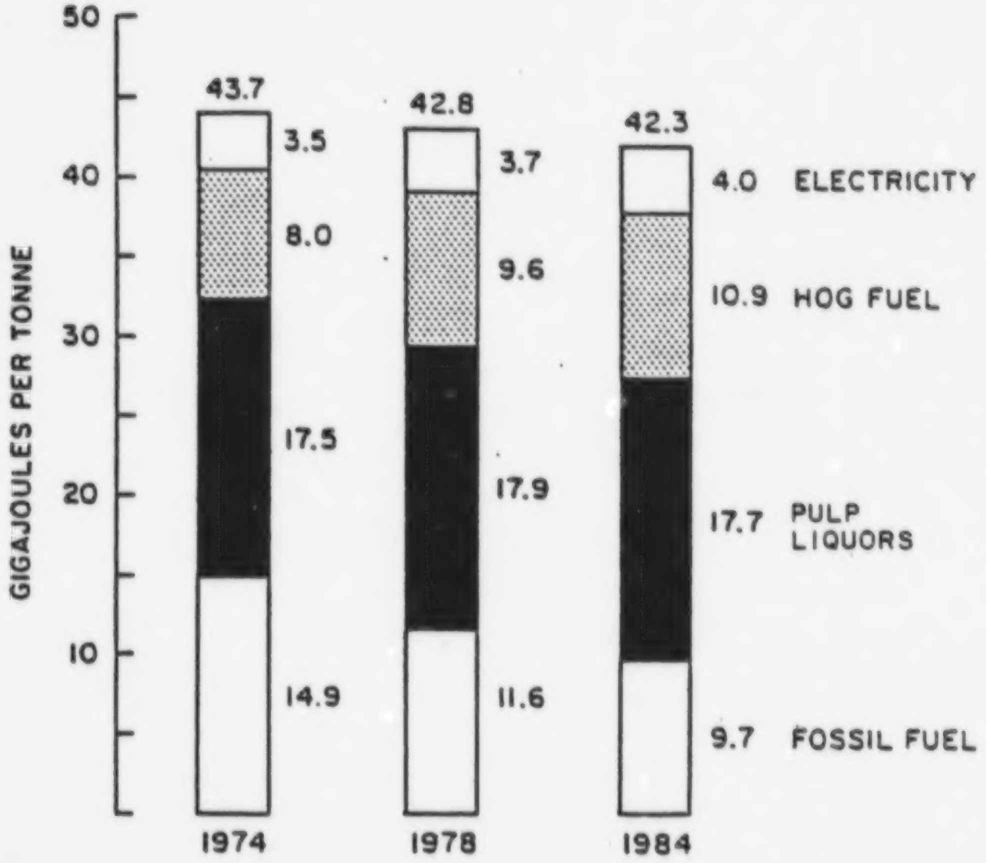
(GJ/t)

	Motive Electricity*[1]	Boiler Electricity	Natural Gas	Residual Fuel Oil	Total Energy*[2]
1972	8.16	-	2.59	6.94	21.00
1976	8.94	-	3.17	5.36	20.60
1977	9.15	-	2.70	5.14	20.08
1978	8.69	-	2.79	5.07	20.17
1979	8.45	-	2.65	4.82	19.54
1980	8.49	-	2.47	4.86	19.20
1981	8.66	-	2.17	4.85	18.95
1982	9.07	-	2.13	5.15	19.64
1983	9.21	0.26	1.87	4.09	19.50
1984	7.66	2.18	2.17	2.91	19.40

*[1] Purchased and self-generated electricity.
*[2] Includes self-generated energy.

Figure 6 - 6

PULP AND PAPER INDUSTRY TOTAL ENERGY CONSUMPTION AND FUEL USE IN BRITISH COLUMBIA



1974 and 1984. The products from these B.C. mills included bleached and unbleached kraft pulp, thermomechanical pulp, newsprint and paper. No correction was made for the difference in energy production for each product. It was generally assumed that each mill was operating at full capacity over the period; however, some energy consumption data from mills was corrected for inefficiencies at less than full production and some was not. Between 1974 and 1984 Interior mills improved efficiency considerably (Fig. 6-7), whereas Coastal mills decreased overall energy efficiency only slightly.[23] However, Coastal mills are still significantly more energy efficient than Interior mills.

The survey of B.C. pulp and paper mills also identified the following energy management projects which were introduced and the number of mills that introduced them:[23]

1. Upgraded steam lines and process equipment systems (6).
2. Replaced incandescent lighting fixtures with more efficient fluorescent sodium or mercury vapour units; skylights and windows were installed where possible (7).
3. Improved building insulation (1).
4. Increased heat recovery from exhaust gas streams (8).
5. Improved lubrication and bearing systems (2). These energy management measures generally accounted for less than 10 percent of energy savings at a mill.

Machinery replacement projects which improved fuel efficiency and the number of plants which undertook these projects were as follows:[23]

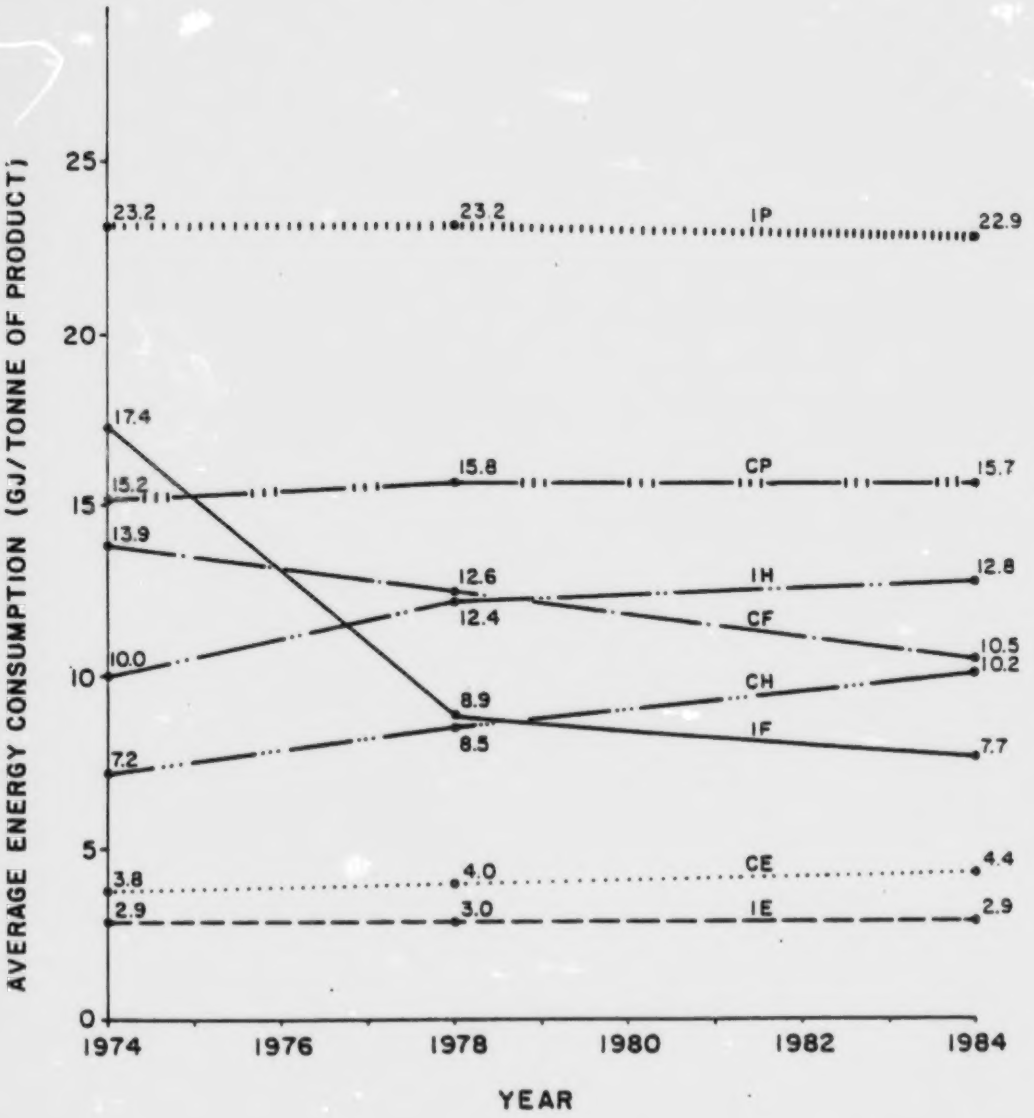
1. Installed computer control on the batch digester system to reduce peak steam demands (6).
2. Installed new boiler controls, gas analyzers and other devices to improve boiler efficiency (11).
3. Upgraded steam condensate recovery systems (7).
4. Modified electric motor selection standards to ensure optimal efficiency (6).
5. Modified the use and selection of process equipment to ensure optimal operating efficiency (6).
6. Upgraded and rehabilitated boiler feedwater heating systems (7).
7. Replaced or upgraded heat exchangers (6).
8. Installed boiler blowdown heat recovery units (4).

Figure 6 - 7

AVERAGE ENERGY CONSUMPTION (GJ/TONNE OF PRODUCT)

	INTERIOR MILLS	COASTAL MILLS
FOSSIL FUELS	IF	CF
ELECTRICITY	IE	CE
HOG FUEL	IH	CH
PULP LIQUORS	IP	CP

		INTERIOR MILLS	COASTAL MILLS
TOTAL AVERAGE ENERGY	1974	53.5	40.0
CONSUMPTION	1978	47.5	40.9
(GJ/TONNE PRODUCT)	1984	46.3	40.7



9. Installed hog fuel drying system (2).

10. Installed hydroelectric generator (1).

11. Installed computer controls on paper machines (1).

12. Installed computer controls on bleach plant and recovery boiler (1).

13. Installed a back pressure turbine generator set (1).

14. Replaced mechanical steam fan drives with electric motors (1).

Collectively, these changes accounted for at least 25 percent of the energy savings.

Process changes which improved fuel efficiency and the number of plants which undertook these changes were as follows:[23]

1. Improved recovery of pulp liquor for firing in chemical recovery units (11).
2. Increased press loading on the paper machine to reduce drying requirements (4).
3. Recycled warm filtrates in the bleach plant (8).
4. Optimized fresh water consumption in the bleaching, pulping and paper making areas (10).
5. Improved distribution of steam for mill heating units (2).
6. Reclaimed compressor cooling water (3).
7. Closed up paper machine white water systems (8).
8. Used waste process hot water in wood rooms to reduce steam requirements (1).
9. Used reclaimed hot water in the bleach plant in lieu of heat exchange from steam (1).
10. Reclaimed motor cooling water (1).
11. Operated refiners at a more constant load by installing a larger refiner stock storage tank (1).

Collectively, approximately 25 percent of the energy savings resulted from process changes.

In 1984 the B.C. pulp and paper industry's average electricity requirement was 1105 kW•h/t of product and this represented a

13 percent increase from 1974 despite an overall increase in energy efficiency.[23] During the same period the use of self-generated electricity had only increased by 4.5 percent. However, the increases in unit electricity requirements were more than compensated by the reduction in process steam requirements.

6.4 BIOMASS

(a) Introduction

Biomass is a general term which includes all types of wood waste (split logs, ends, slabs, edgings, butts, bark, planer shavings, sawdust, forest residue, non- commercial trees, driftwood and trees from tree farms) bagasse (sugar cane refuse), fruit fibres and shells, coffee grounds, coffee, rice and corn husks, municipal solid waste, sewer sludge, dung and peat. Wood waste, municipal solid waste and sewer sludge are technically feasible as sources of energy in B.C.

Wood waste in B.C. is produced by the lumber, shake and shingle, veneer and plywood, pulp and paper mills and their associated logging operations either as mill waste, forest residues or stands of noncommercial timber. Sawmill waste is the principal feasible source of woodwaste, but it is not homogeneous. The proportion of sawdust, bark, planer shavings, chip fines, sander dust and plywood trim varies with the tree species utilized, the manufacturing process, market conditions in various sectors of the forest industry and the amount of wood waste utilization practiced.[24] However, Table 6-6 is typical of the composition of wood waste from an Interior B.C. sawmill.

Forest residues consist of unprocessed logging slash, trees less than 150 mm in diameter, split logs, broken ends and butts, and trees with rotten cores which are left in the forest at landings, along logging roads and at land sorts.[24] Estimates of the quantities of wood fuel available from forest residues or tree farms depend largely on the specific forest region, type of trees, age of the timber stand, nature of the terrain and the utilization standards in force. Over the years, several independent studies have indicated that unharvested forest residues range between 10 and 26 percent of the allowable cut for coastal regions. With current close utilization standards and better forest management this range has decreased to between 5 and 15 percent of the cut depending on the particular site.

Municipal solid waste and sewer sludge are small components of the available energy from biomass in B.C. However, municipal solid waste has been developed for steam production in Vancouver.

In conclusion, the largest potential for biomass utilization in B.C. is in the form of hog fuel from the forest industry.

TABLE 6-6

MIX OF WOOD WASTE FROM A TYPICAL INTERIOR B.C. SAWMILL

	(Wt. %)
Bark	32.0
Sawdust	39.7
Chip Rejects	18.7
Planer Shavings	5.6
Planer Trim	4.0

The utilization of hog fuel is affected by the technology and economics of recovery, loading, hauling, chipping and processing.

(b) Availability and Uses of Hog Fuel

The pulp and paper mills have the largest cogeneration facilities and are the largest consumers of hog fuel in B.C. The location, capacity, products and roundwood requirements of pulp and paper mills in B.C. are listed in Table 6-7.[25] The locations of pulp mills are illustrated in Figure 6-8.

In 1978/79, when the pulp, paper and wood product segments were working near capacity, the coastal part of the industry was producing hog fuel totalling 26.5 percent of the volume of wood harvested.[25] In 1985, a total of 20.83 x 10^6 m^3 (3,720,000 GPU or 3,380,000 BDt) of hog fuel was produced in the South Coastal Region of British Columbia.[26] Approximately 87 percent or 18.12 x $10^6 m^3$ (3,250,000 GPU) was utilized. The uses for this hog fuel are summarized as follows:

1. 80 percent was used in the production of steam/power.
2. 10 percent was used for pulp furnish.
3. 4 percent was used for board furnish.
4. 6 percent was used for a diversity of local uses.

The uses of hog fuel and types of Coastal mills which use hog fuel are summarized in more detail in Table 6-8.[26] Sawmills were the major producers of hog fuel (70 percent), but pulp mills were the major consumers (70 percent). Therefore, the production of hog fuel depends primarily on the operating level of the forest industry. Between 1977 and 1985 the production of hog fuel decreased despite an increase in lumber/plywood production because of more efficient wood utilization. However, it increased again from 3,380,000 BDT to 3,519,506 BDT between 1985 and 1989 (Table 6-9). This resulted from less wood being left in the bush, but instead separated at log sorts or mills.

Hog fuel production is expected to remain relatively constant over the next five years or more because conflicting factors controlling production tend to balance.

Factors which could increase hog fuel production are as follows:

1. The allowable annual cut is expected to remain relatively constant at slightly less than recent harvest levels.

TABLE 6-7

LOCATION, CAPACITY, PRODUCTS AND ROUNDWOOD REQUIREMENTS OF PULP AND PAPER MILLS IN B.C.*[1]

Company	Mill Location	Annual Capacity (k tonnes) Pulp	Annual Capacity (k tonnes) Paper	Product Types	Roundwood Requirement (10^3m^3)
Coastal Mills					
Canadian Pacific Forest Prod.	Gold River	230	75	bleached kraft pulp, newsprint	1200
				kraft paper	810
				kraft paper	1820
Eurocan Pulp & Paper	Kitimat	300	300	liner board, kraft paper, CMP	1500
Fletcher Challenge	Campbell River	770	510	newsprint, bleached kraft pulp, TMP,	
	New Westminster	0	60	hardboard	-
Howe Sound Pulp	Port Mellon	180	0	bleached, semi-bleached and unbleached	
Island Paper Mills	New Westminster	0	112	fine paper	0
MacMillan-Bloedel	Nanaimo	340	0	bleached kraft pulp	1350
	Port Alberni	452	382	newsprint, semi-bleached kraft pulp	1020
	Powell River	670	620	newsprint, semi-bleached kraft pulp	
				grounded speciality paper	1600
Paperboard Industries	Burnaby	0	150	recycled paperboard	0
Scott Paper Co.	New Westminster	26	90	tissue, sanitary paper	75
Skeena Cellulose	Prince Rupert	369	0	bleach kraft pulp	1600
Western Pulp	Woodfibre	150	0	bleached kraft pulp	750
	Port Alice	140	0	sulphite pulp	700

TABLE 6-7 - (Cont'd)

Company	Mill Location	Annual Capacity (k tonnes) Pulp	Annual Capacity (k tonnes) Paper	Product Types	Roundwood Requirement ($10^3 m^3$)
Interior Mills					
Canadian Forest Products:					
Intercontinental Pulp	Prince George	200	-	bleached and unbleached kraft pulp	1080
Prince George Pulp and Paper	Prince George	160	90	bleached kraft pulp, kraft sack and bag	1310
Cariboo Pulp and Paper	Quesnel	260	-	bleached kraft pulp	1260
Crestbrook Forest Industries	Skookumchuck	575	-	bleached kraft pulp	2790
Fibreco Export	Taylor	160	-	chemi-mechanical pulp	-
Finlay Forest Industries	Mackenzie	145	70	bleached mechanical groundwood,	
Fletcher Challenge					
Northwood Pulp and Timber	Prince George	470	-	bleached softwood kraft and groundwood pulp	2670
Quesnel River Pulp	Quesnel	160	-	TMP, CTMP	350
Skeena Cellulose	Castlegar	175	-	bleached kraft pulp	960
Weyerhaeuser Canada	Kamloops	410	-	bleached kraft pulp	1850

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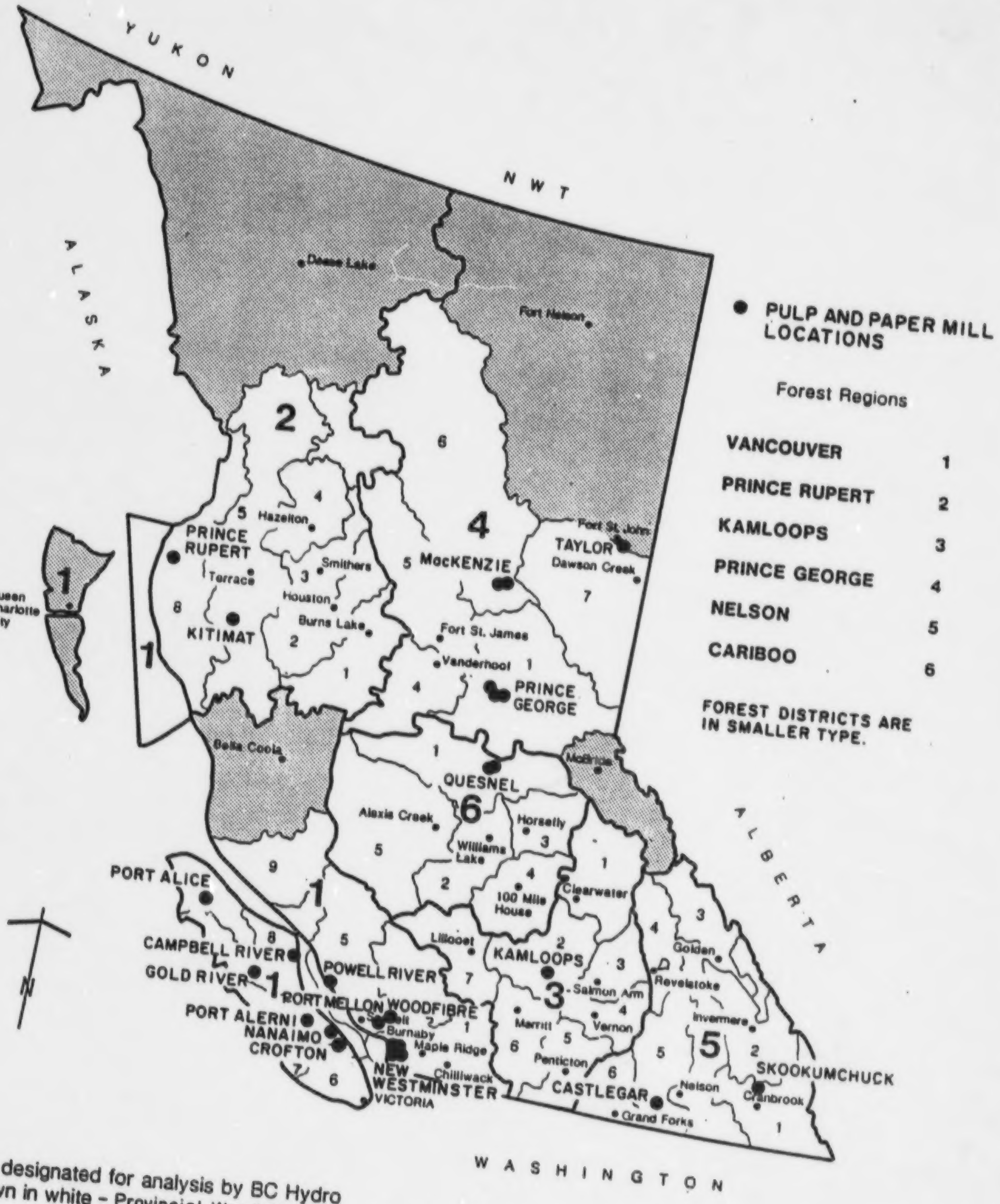
*[1] Capacities and roundwood requirements are estimated partly from information in the Pulp and Paper Directory (1987).


YUKON
NWT
ALASKA
ALBERTA
WASHINGTON
● PULP AND PAPER MILL LOCATIONS
Forest Regions
VANCOUVER 1
PRINCE RUPERT 2
KAMLOOPS 3
PRINCE GEORGE 4
NELSON 5
CARIBOO 6
FOREST DISTRICTS ARE IN SMALLER TYPE.
Dease Lake
Fort Nelson
Fort St. John
TAYLOR
Dawson Creek
MacKENZIE
Hazelton
PRINCE RUPERT
Terrace
Smithers
Houston
Burns Lake
KITIMAT
Queen Charlotte City
Fort St. James
Vanderhoof
PRINCE GEORGE
Bella Coola
McBride
QUESNEL
Alexis Creek
Horsefly
Williams Lake
100 Mile House
Clearwater
PORT ALICE
CAMPBELL RIVER
GOLD RIVER
POWELL RIVER
Lillooet
KAMLOOPS
Salmon Arm
Revelstoke
Golden
PORT MELLON
WOODFIBRE
Sechelt
Burnaby
Maple Ridge
Chilliwack
PORT ALBERNI
NANAIMO
CROFTON
NEW WESTMINSTER
VICTORIA
Merritt
Vernon
Penticton
CASTLEGAR
Grand Forks
Nelson
Invermere
SKOOKUMCHUCK
Cranbrook
N
1
2
3
4
5
6
7
8
9

Districts designated for analysis by BC Hydro are shown in white - Provincial Wood Waste Supply Study

FIGURE 6-8

B.C. PULP AND PAPER MILL LOCATIONS

TABLE 6-8

USES OF HOG FUEL ON THE SOUTH COAST OF BRITISH COLUMBIA, 1985

Mill Type	Quantity (10^3 BDT)	Use
Sawmills	348	Steam/Power
Pulp Mills	259	Pulp Furnish
	1635	Steam/Power
Board Mills*[2]	124	Board Production
Plywood/Board Mills	162	Steam/Power
Shake/Shingle Mills	12	Steam/Power
Remanufacturing Plants	19	Steam/Power
Other	147	Diverse Local Uses
Export	143	Steam/Power or Pulp Furnish
TOTAL	2849	

---

*[1] Density of average bone dry coastal B.C. hog fuel is 154 kg/m^3.
*[2] Hardboard and particle board.

TABLE 6-9

SOURCES OF WOOD WASTE

Forest Region	Mill Waste Residue (BDT)	Mill Waste Surplus (BDT)	Total Surplus (1989) (BDT)*[1]	Total Surplus (1995) (BDT)*[1]
Vancouver*[2]	3,519,500	944,900*[3]	1,033,300	-115,100
Prince Rupert	786,500	520,700*[4]	520,700	-475,400
Prince George	1,659,300	1,395,700*[5]	1,395,700	922,600
Cariboo*[6]	1,057,500	897,900*[7]	897,900	394,400
Kamloops	1,042,300	622,900*[8]	622,900	126,900
Nelson	1,167,600	886,000*[9]	886,000	548,300
TOTALS	9,232,700	5,268,100	5,356,500	1,401,700

*[1] Includes debris from debris traps as well as a few land sorts and one urban debris site, but does not include wood waste from landings and roadsides.

*[2] Excludes new, committed generation at Port Mellon (85 MW and 700 GW.h per annum). Approximately 80% of the mill waste surplus in this region is in the Chilliwack Forest District, along the Fraser River.

*[3] Potential and committed expansions and other self-generation/load displacement projects at Port Mellon, New Westminster, Port Moody, Squamish, Powell River, Nanaimo, Campbell River, Crofton and Gold River would be competing for this surplus wood waste.

*[4] The surplus is divided among Burns Lake, Hazelton, Smithers and Houston.

*[5] Approximately 45% of the surplus is in the Prince George District with other significant surpluses at Mackenzie, Vanderhoof and Fort St. James.

*[6] Wood waste for new, committed generation at Williams Lake and wood waste for the proposed fibreboard plant have been subtracted only from the Total Surplus (1995) column. The new generating plant would have a capacity of 55 MW and annual electricity generation of 438 GW.h.

*[7] The surplus is divided with approximately 40% each at Quesnel and Williams Lake and the remaining 20% at 100 Mile House.

*[8] The surplus is divided with approximately 18% each at Clearwater, Vernon, Penticton and Lillooet.

*[9] The mills are spread over the districts. However, there are significant concentrations at Cranbrook, Skookumchuck, Elko, Creston, Canal Flats, Nakusp and Midway.

2. Utilization technology improvements will permit the use of waste tree species.

3. Advanced silvicultural techniques could increase annual growth rates.

4. The use of existing roads in second growth stands should permit intermediate cuts.

5. The use of smaller trees will result in increased wastage per unit of useable wood.

Factors which could decrease hog fuel production are as follows:

1. More lands will be withdrawn for other single uses.

2. Recent overcutting resulted from removal of fire damage and beetle kills.

3. Less timber will be available from private and Indian lands.

4. There will be a "falldown effect" from having less volume of wood per hectare in second growth stands.

5. Global warming may adversly affect the growth rates of some tree species.

The production of hog fuel at Interior and North Coast mills is summarized in Table 6-9[1]. It is estimated that the combined total from all regions is approximately 9,233,000 BDTs. Of this total, less than half is presently utilized. The surplus of 5,268,000 BDTs is expected to be reduced to approximately 1,402,000 BDTs by 1995 if contracts are signed with independent power producers and cogenerators who are presently negotiating as a result of B.C. Hydro's requests for proposals and expressions of interest. By 1995 there could be hog fuel supply deficits in the Vancouver and Prince Rupert regions. However, these deficits could be offset by using additional local or adjacent resources - garden waste in the Vancouver Region and hog fuel from nearby mills in the Prince George region for supply to the Prince Rupert Region. In addition, more hog fuel could be available because it is expected that a number of the proposed projects will not be developed and that would reduce the demand for hog fuel resources.

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[1] Stewart and Ewing Associates Ltd. 1990. Provincial Wood Waste Supply and Utilization Study. Report prepared for B.C. Hydro.

Hog fuel availability is affected by the swings in the demand for lumber because the main source of supply is sawmills. Even with hog fuel storage, the duration of these swings could cause supply problems.

Potential sources of wood waste for hog fuel include settings, landings, non-commercial standing timber, mill waste, driftwood, dry land sortyard debris, and tree farms. These sources are described briefly in the following sections.

(i) Landings and Settings

The extractable volumes of wood waste from B.C. Coastal regions are summarized in Table 6-10.[25] The ratio of wood waste at landings to wood waste in the setting ranges between 2.7 and 4.0 to 1. The higher ratios are concentrated in the South and Mid-Coast regions. The size of pieces at the landings is larger than pieces left in the bush. Therefore, much of the wood waste on a volume basis is readily available at landings (Table 6-10).

The average volume of wood waste produced in the Vancouver Forest Region in 1981 was estimated to be $70 m^3/ha$[27] (including wood waste in the bush and at landings). The amount of wood waste varied with the amount of wood of non-commercial species, age of the trees, types of commercial species, amount of rot and the slope of the hillside.

The yarding method was also governed partly by the slope and it affected log recovery. Grapple yarding produced less wood waste on settings for slope classes 1 to 3, but high lead yarding produced less wood waste for slope classes 4 and 5 (Fig. 6-9). Slope classes are summarized in Table 6-11. Grapple yarders are also more adaptable to smaller log sizes than high lead yarders. Concentrations of wood waste were 234 m^3/ha for high lead landings Class 3 and 276 m^3/ha at grapple landings Class 4 (Fig. 6-10). Steeper slopes tended to produce higher wood waste concentrations in the bush because of more breakage on falling and higher concentrations at the landings because of more breakage during yarding. However, there was no pattern between high lead or grapple yarding and slope class in determining the volume of wood waste produced at landings.

(ii) Forest Logging Residues

Forest logging residues include all slash, intermediate cuttings, windfalls and non-merchantable wood left in the woods after commercial logging operations. Some of these residues are left at roadsides or landings because

TABLE 6-10

EXTRACTABLE VOLUMES OF WOOD WASTE ON THE B.C. COAST

Region	Slash Volume	
	Landings (m^3/ha)	Setting*[1] (m^3/ha)
Queen Charlotte Islands	114	42
North Coast Mainland	116	43
Mid-Coast Mainland	135	36
South Coast Mainland	132	33
East Vancouver Island	114	43
West Vancouver Island	113	43
AVERAGE	121	40

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*[1] Left in the bush.

Figure 6 - 9

VOLUME OF WASTE WOOD ON THE SETTING, BY SLOPE CLASS AND YARDING METHOD, VANCOUVER REGION, 1981.

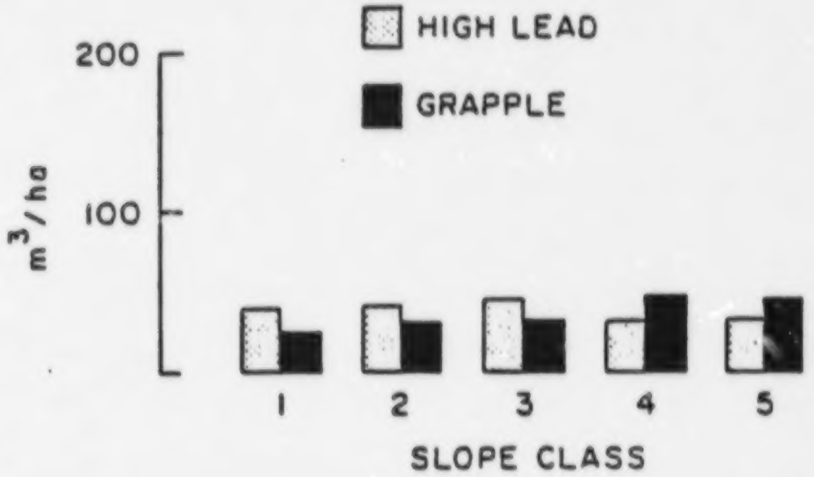

Figure 6 - 10

VOLUME OF WASTE WOOD ON LANDINGS, BY SLOPE CLASS AND YARDING METHOD, VANCOUVER REGION, 1981

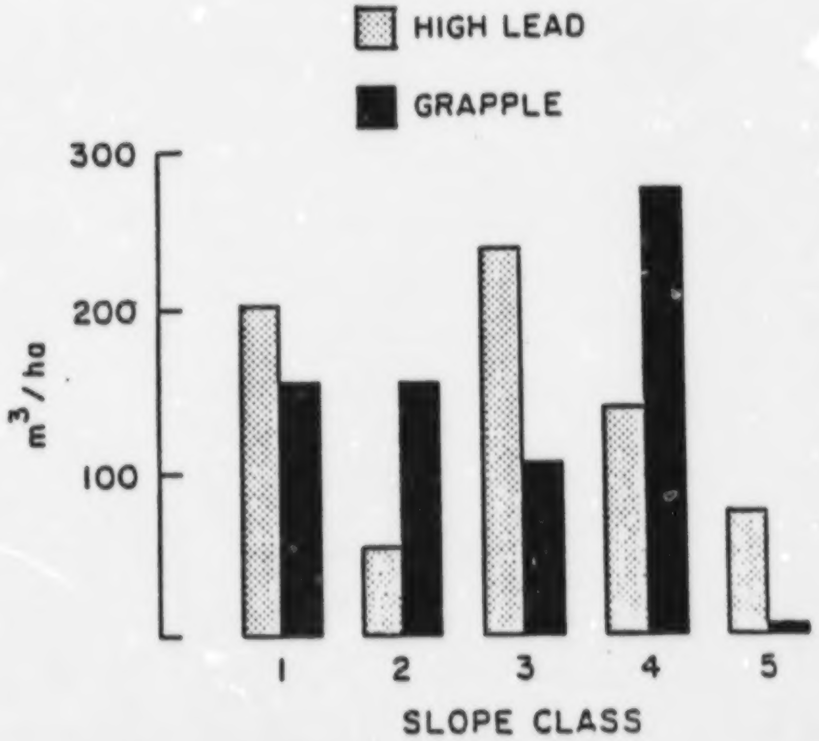

TABLE 6-11

SLOPE CLASSES

Slope Class	Slope Percent	Slope Degrees
1	0-10	0-6
2	11-20	7-11
3	21-33	12-18
4	34-50	19-27
5	>50	>27

some lower grade material and short or small diameter logs are retrieved and log breakage occurs during yarding. These residues could conceivably be collected during or after the logging operation and transported to a mill or hogging facility for conversion to useable fuel. Estimates of the quantities of waste wood available from forest residues depends largely on the specific forest region and include the age of the timber stand, the nature of the terrain and the utilization standards in force. The Coastal region generally produces more wood waste than Interior regions.

Several independent studies indicate that the unharvested forest residues consisting of timber classed as merchantable under current utilization standards range between 5 to 13 percent for Interior regions and 10 to 26 percent for Coastal regions.[6] This is estimated to be between 2.25 million and 7.5 million GPU/a of recoverable wood waste (an average of 60 percent of the wood waste resource produced from mill residues). Higher recovery rates could be expected initially because of the accumulation of logging debris in previously logged areas. The logging debris would be available for energy production if it could be economically recovered because it is not committed to any other use. Forest residues could be collected during or after the logging operation and transported to a generating facility for conversion to useable fuel.

Similarly, a stand of non-commercial timber could be dedicated for fuelling a generating station. At this time, the harvest of hardwoods such as white birch, trembling aspen, black cottonwood, red alder and big leaf maple is only about 16 percent of the Annual Allowable Cut, and it is a potential hog fuel resource.[6] Some hardwoods are processed for secondary wood manufacturing and a limited amount of hardwood chips is used in pulp production. The hardwood stands are expected to be a depletable resource because the areas that have been cleared would most likely be re-seeded with commercial softwood trees.

The most suitable hardwood stands in the South Coast region are located on the east coast of Vancouver Island, cover 70 500 ha and could supply 17 500 GPU/a over a 30-year period (sufficient to fuel a 3 MW generating station).[6] The Prince George region is particularly under utilized with at least 50 000 GPU/a of surplus hardwoods available for hog fuel production (sufficient to fuel a 10 MW generating station). This resource could best be utilized to supplement fuel for another justifiable wood waste energy conversion project because of these limited concentrations of non-commercial standing timber.

- There are numerous stands of decadent wet belt cedar and hemlock in the B.C. Interior that are not economical to log because of the low sawlog volumes recovered.[28] In some areas sawlog values are as low as 25 percent of the wood in a logging area. In tests conducted near Vernon, B.C., approximately 60 percent of the chips from the non-sawlog material was suitable for pulp and the remaining 40 percent could be used for hog fuel.

(iii) Driftwood and Floating Debris

Logs are often boomed for transport or temporary storage. Storms often break booms and wash these logs and other windfalls onto beaches. Salvage of driftwood and floating debris from rivers, lakes, reservoirs and beaches is a potential wood waste resource, but like forest residue from previous logging operations it is a relatively short term depletable resource.[6] Driftwood and floating debris are selectively recovered for use in the forestry industry by salvage operators who leave only lower quality material for potential wood waste recovery. A study by the Council of Forest Industries of British Columbia in 1974 indicated that 2.9 percent (820 000 m^3) of the Coast log production is lost during handling and boom transport. However, this loss has decreased significantly with the increased use of log barges. Log salvage operations recover 40 percent of the driftwood logs, 35 percent are sinkers and 25 percent are lost to the beaches and the open sea. Less than 100 000 GPU/a of this waste wood could be recovered for energy conversion. The B.C. Debris Control Board maintains a debris trap near Agassiz and collection sites near the mouth of the Fraser River and on Howe Sound. Approximately 150,000 m^3 of loosely packed wood waste (60,000 BDT) is collected at these sites annually.[2] Of this amount 20 to 25 percent is salvaged for logs and firewood and the remainder is burned in open fires.

The dispersed nature of the driftwood resource, difficulty in salvaging, high sand content and/or high salt content make it impractical to use most of these resources effectively.

(iv) Urban Waste

Wood waste in the urban environment includes wood from tree removal and pruning as well as scrap lumber and plywood. It was estimated that 11,200 BDT were processed at a North Vancouver site and sent to a landfill. Extrapolated over the Lower Mainland, it is expected that there are 162,000 BDT produced each year at a large number of widely dispersed sites.[3]

---

[2] B.C. Debris Control Board Annual Report 1988.

(v) Dry Land Sortyards

A study by Smith (1977) indicated that approximately 5 m^3 of wood debris is produced at dry land sortyards for each 100 m^3 of solid wood handled.[29] Approximately half or 2.5 m^3 of the total wood debris is potentially recoverable and consists of 1.5 m^3 of fibre and 1 m^3 of hog fuel.

(vi) Forest Product Mills

Typical yields of wood waste from forest product mills are summarized in Table 6-12.[2] Some wood chips, shavings, sawdust and sander dust supplement pulp logs as raw materials for pulp mills. Flowsheets for each type of mill are illustrated in Figs. 6-11 through 6-16.[2] The wood wastes produced at each stage in the processes are noted on the figures. Waferboard, particle board and shingle mills are representative of specialty product mills and flowsheets vary within a single mill type.

(vii) Tree Farms

A tree farm, as defined in this report, is a tract of forest managed on a sustained yield basis in order to provide a reliable source of fuel for electrical power generation. To date, the harvest of hardwoods, such as white birch, trembling aspen, black cottonwood, red alder, and big leaf maple in British Columbia is only about 16 percent of the Annual Allowable Cut, and thus these trees are a potential source of wood fuel.[24]

Under suitable circumstances wood fuel could be obtained from an area dedicated as a tree farm for fast- growing, short-rotation trees. This is more likely to be viable on the South Coast and Vancouver Island regions where there are dense red alder stands. However, tree farming requires relatively flat terrain which permits maximum mechanization.

Red alder (Alnus rubra) is a fast-growing indigenous tree found in lower river bottom areas of coastal B.C. It could be a viable wood source over the long term. Approximately 4.24 OD tonnes of red alder wood fuel could be produced annually per hectare.[34] It is expected

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[3] Stewart and Ewing Associated Ltd. 1990. Provincial Wood Waste Utilization Study. Report completed for B.C. Hydro.

TABLE 6-12

PRODUCT YIELDS FROM FOREST PRODUCTS MILLS[30,31,32]

	Pulp & Paper (OD kg/m^3 of Lumber)	Sawmills (OD kg/m^3 Wood)	Plywood (OD kg/m^3 of Product)*[3]	Waferboard (OD kg/m^3 of Product)*[4]	Particleboard (ODkg/m^3 of Product)*[4]	Shingle (OD kg/m^3 of Product)*[7]
Bark	56*[1], 67*[2]	108	135	180	-	20*[7]
Sawdust & Sander Dust	N/A	89	22	217*[5]	69.5	249
Shavings	-	79	-	-	-	-
Chip Fines	5*[1], 4-6*[2]	-	-	-	-	-
Log Trim	-	-	47	-	58.4	-
Core	-	-	51	-	-	-
Green Clippings, Roundup & Spurtrim	-	-	256	-	-	-
Dry Veneer Loss & Panel Trim	-	-	90	-	-	-
Spalts	-	-	-	-	-	67
Knee Bolter & Splitter	-	-	-	-	-	30
Splints	-	-	-	-	-	106
Wood Chips	-	202	-	-	-	-

Note: These yields can be compared with wood waste yields from B.C. Interior sawmills which are listed in Table 6-6.

---

*[1] Based on hemlock from Vancouver Forest Region.
*[2] Based on spruce from Prince George Forest Region.
*[3] Based on 9.5 mm (3/8 in.) plywood from Oregon, product density of 475 kg/m^3.
*[4] Based on 12.7 mm (1/2 in.) waferboard from U.S., product density of 641 kg/m^3.
*[5] Includes log trim and rejects.
*[6] Product density is 481 kg/m^3.
*[7] Assuming 6.2 percent of cedar log fuel is bark (oven dried weight).[33]

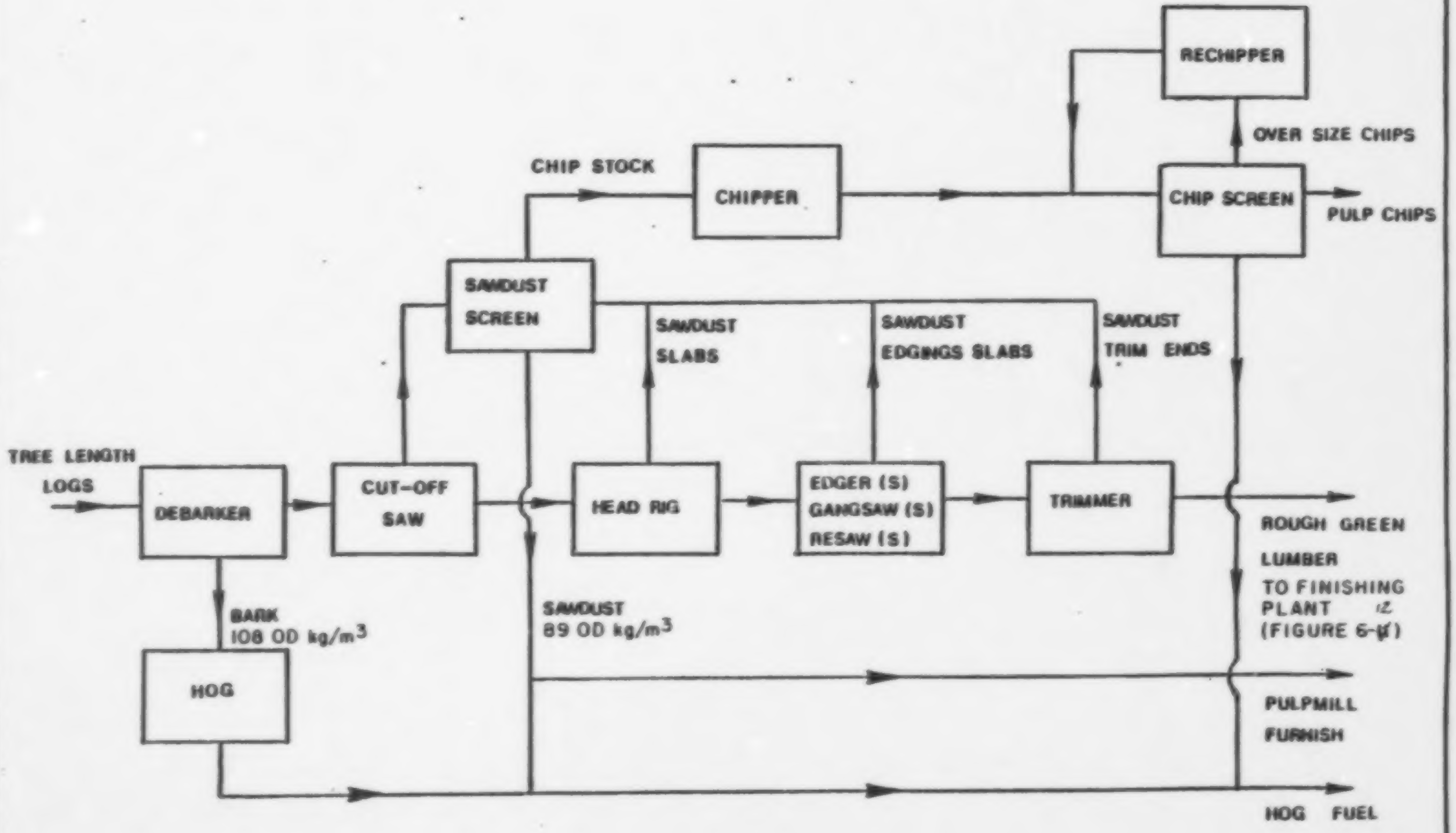
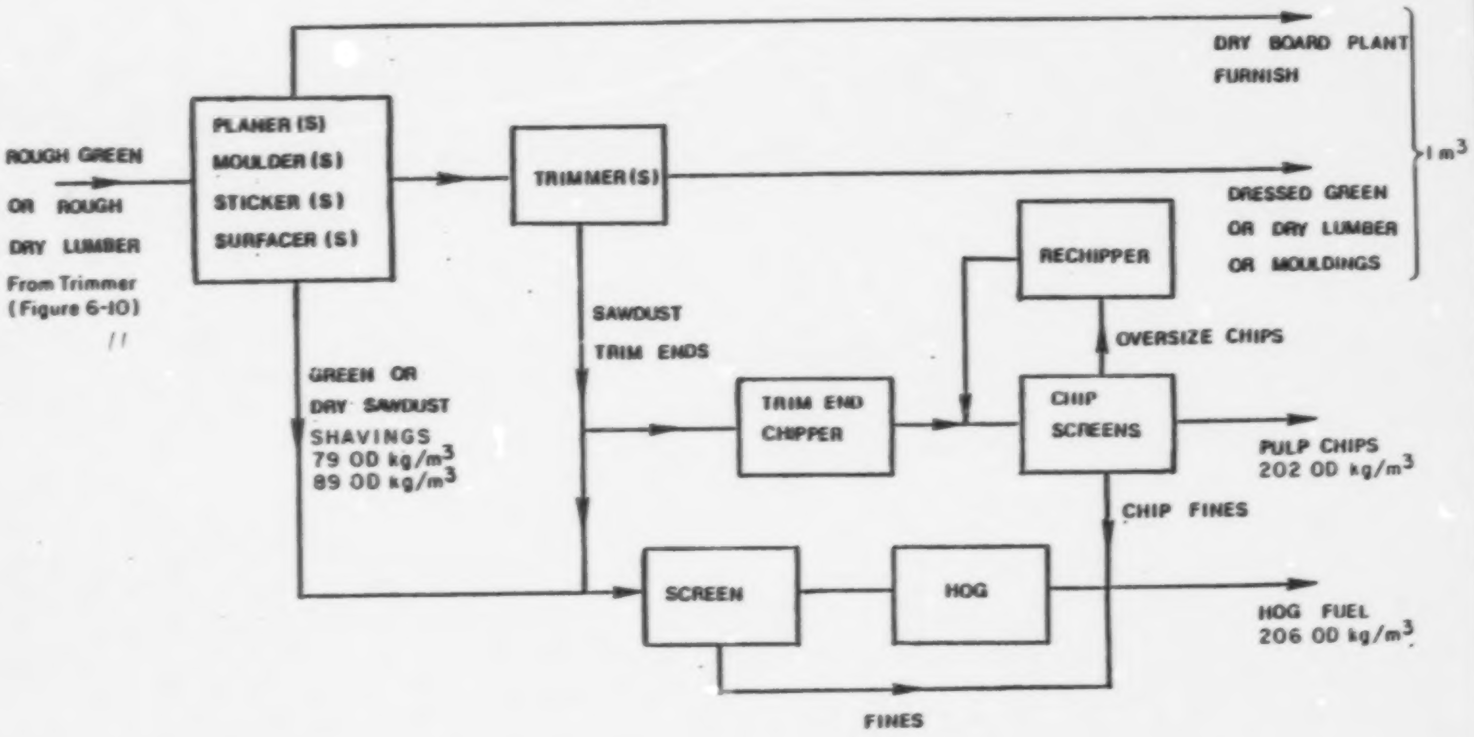

TREE LENGTH
LOGS
DEBARKER
CUT-OFF SAW
SAWDUST SCREEN
CHIP STOCK
CHIPPER
RECHIPPER
OVER SIZE CHIPS
CHIP SCREEN
PULP CHIPS
SAWDUST
SLABS
SAWDUST
EDGINGS SLABS
SAWDUST
TRIM ENDS
HEAD RIG
EDGER (S)
GANGSAW (S)
RESAW (S)
TRIMMER
ROUGH GREEN
LUMBER
TO FINISHING
PLANT 12
(FIGURE 6-~~1~~)
BARK
108 OD kg/m³
HOG
SAWDUST
89 OD kg/m³
PULPMILL
FURNISH
HOG FUEL

FIGURE 6-11 FLOWSHEET OF SAWMILL PRODUCING LUMBER, PULPCHIPS AND HOG FUEL



ROUGH GREEN
OR ROUGH
DRY LUMBER
From Trimmer
(Figure 6-10)
PLANER (S)
MOULDER (S)
STICKER (S)
SURFACER (S)
TRIMMER (S)
DRY BOARD PLANT
FURNISH
DRESSED GREEN
OR DRY LUMBER
OR MOULDINGS
1 m3
RECHIPPER
OVERSIZE CHIPS
SAWDUST
TRIM ENDS
GREEN OR
DRY SAWDUST
SHAVINGS
79 OD kg/m3
89 OD kg/m3
TRIM END
CHIPPER
CHIP
SCREENS
PULP CHIPS
202 OD kg/m3
CHIP FINES
SCREEN
HOG
HOG FUEL
206 OD kg/m3
FINES

FIGURE 6-12 FLOWSHEET OF LUMBER FINISHING PLANT PRODUCING LUMBER, PULP CHIPS, PLANER SHAVINGS AND HOG FUEL

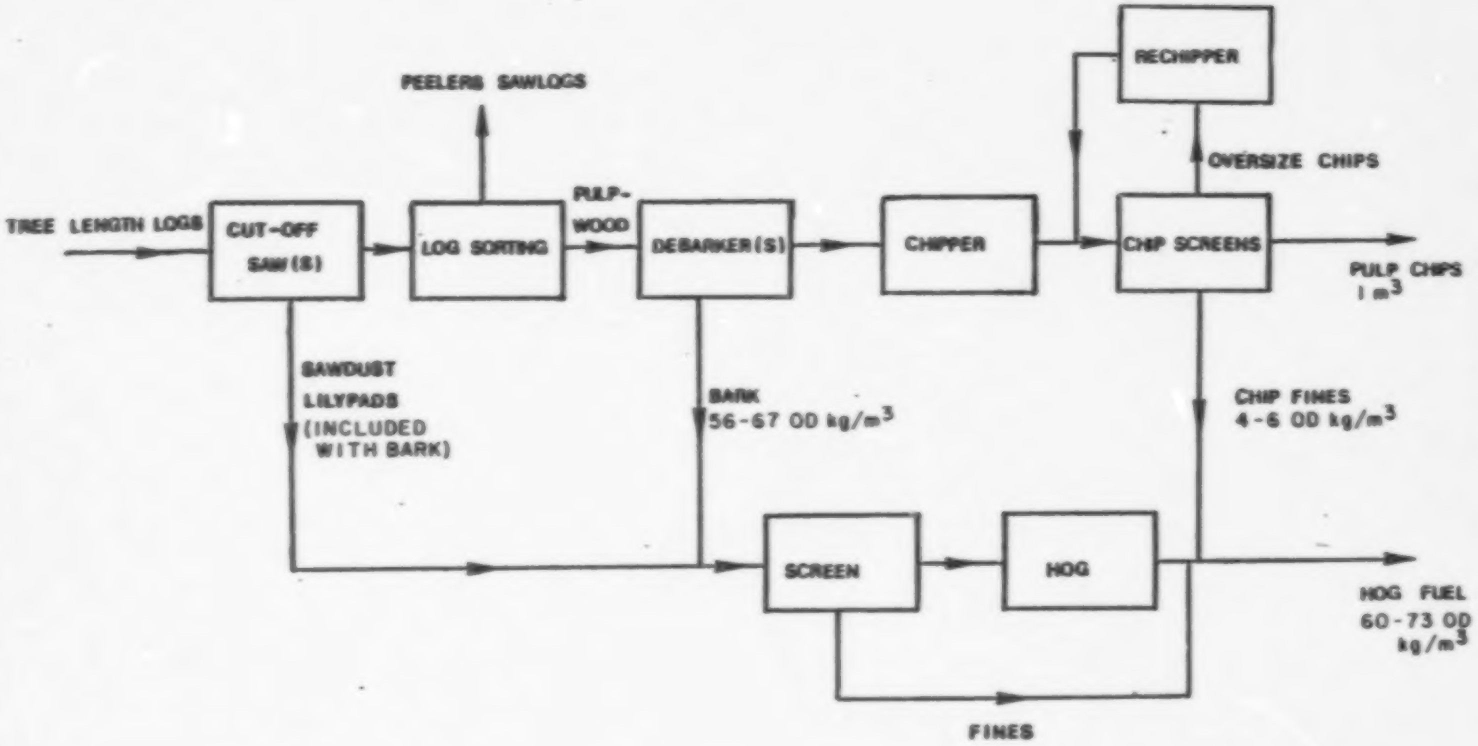

TREE LENGTH LOGS
CUT-OFF SAW(S)
LOG SORTING
PEELERS SAWLOGS
PULP-WOOD
DEBARKER(S)
CHIPPER
RECHIPPER
OVERSIZE CHIPS
CHIP SCREENS
PULP CHIPS 1 m³
SAWDUST LILYPADS (INCLUDED WITH BARK)
BARK 56-67 OD kg/m³
CHIP FINES 4-6 OD kg/m³
SCREEN
HOG
HOG FUEL 60-73 OD kg/m³
FINES

FIGURE 6-13 FLOWSHEET OF PULP MILL WOOD ROOM TREE-MERCHANDIZER CONCEPT PRODUCING PULP CHIPS, HOG FUEL, PEELERS AND SAWLOGS

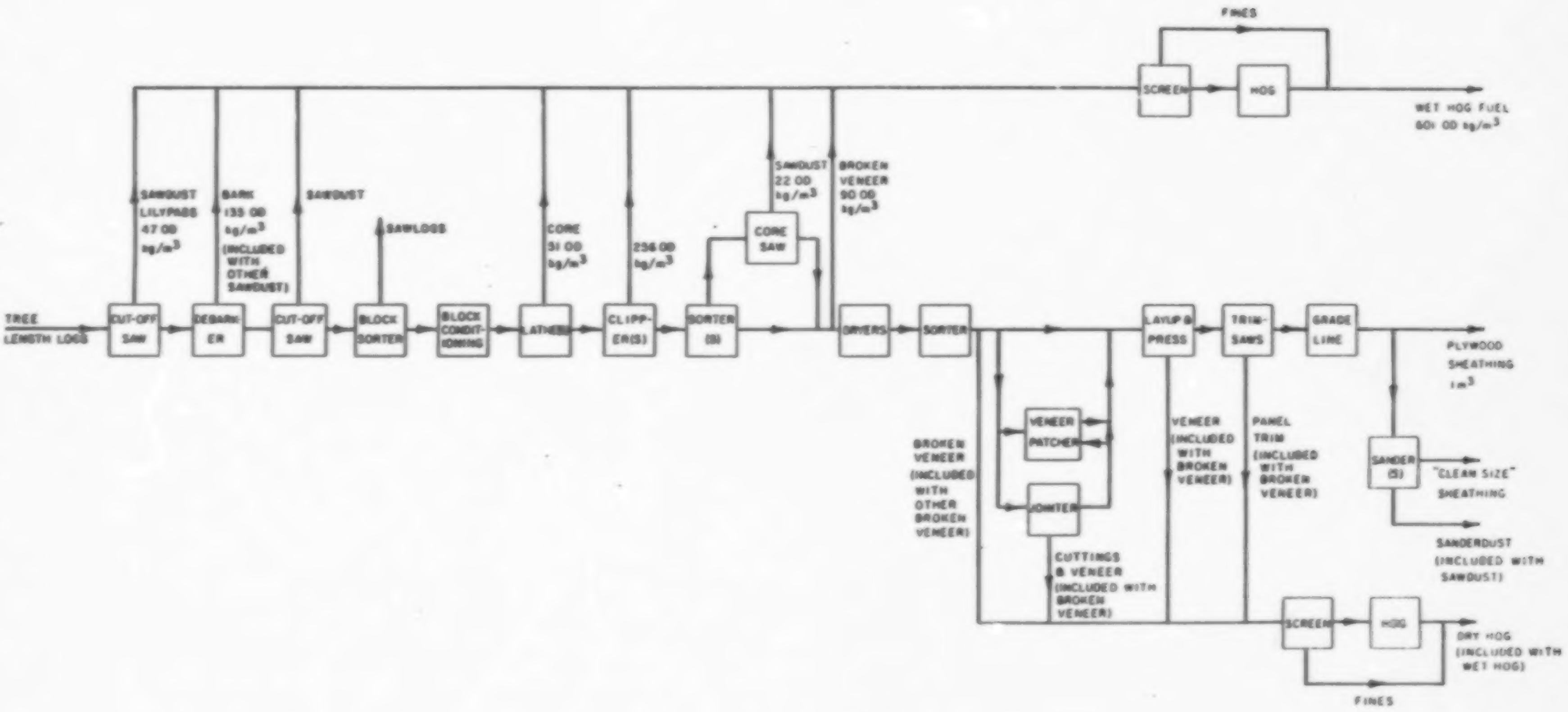

TREE LENGTH LOGS
CUT-OFF SAW
DEBARK-ER
CUT-OFF SAW
BLOCK SORTER
BLOCK CONDIT-IONING
LATHES
CLIPP-ER(S)
SORTER (S)
CORE SAW
DRYERS
SORTER
VENEER PATCHER
JOINTER
LAYUP & PRESS
TRIM-SAWS
GRADE LINE
SANDER (S)
SCREEN
HOG
SAWDUST LILYPADS 47 OD kg/m^3
BARK 133 OD kg/m^3 (INCLUDED WITH OTHER SAWDUST)
SAWDUST
SAWLOGS
CORE 31 OD kg/m^3
236 OD kg/m^3
SAWDUST 22 OD kg/m^3
BROKEN VENEER 90 OD kg/m^3
FINES
WET HOG FUEL 601 OD kg/m^3
PLYWOOD SHEATHING 1 m^3
BROKEN VENEER (INCLUDED WITH OTHER BROKEN VENEER)
VENEER (INCLUDED WITH BROKEN VENEER)
PANEL TRIM (INCLUDED WITH BROKEN VENEER)
"CLEAN SIZE" SHEATHING
SANDERDUST (INCLUDED WITH SAWDUST)
CUTTINGS & VENEER (INCLUDED WITH BROKEN VENEER)
DRY HOG (INCLUDED WITH WET HOG)
FINES

Figure 6-14

FLOWSHEET OF TYPICAL WESTERN SOFTWOOD SHEATHING PLYWOOD MILL SHOWING HOG FUEL AND SANDERDUST SOURCES

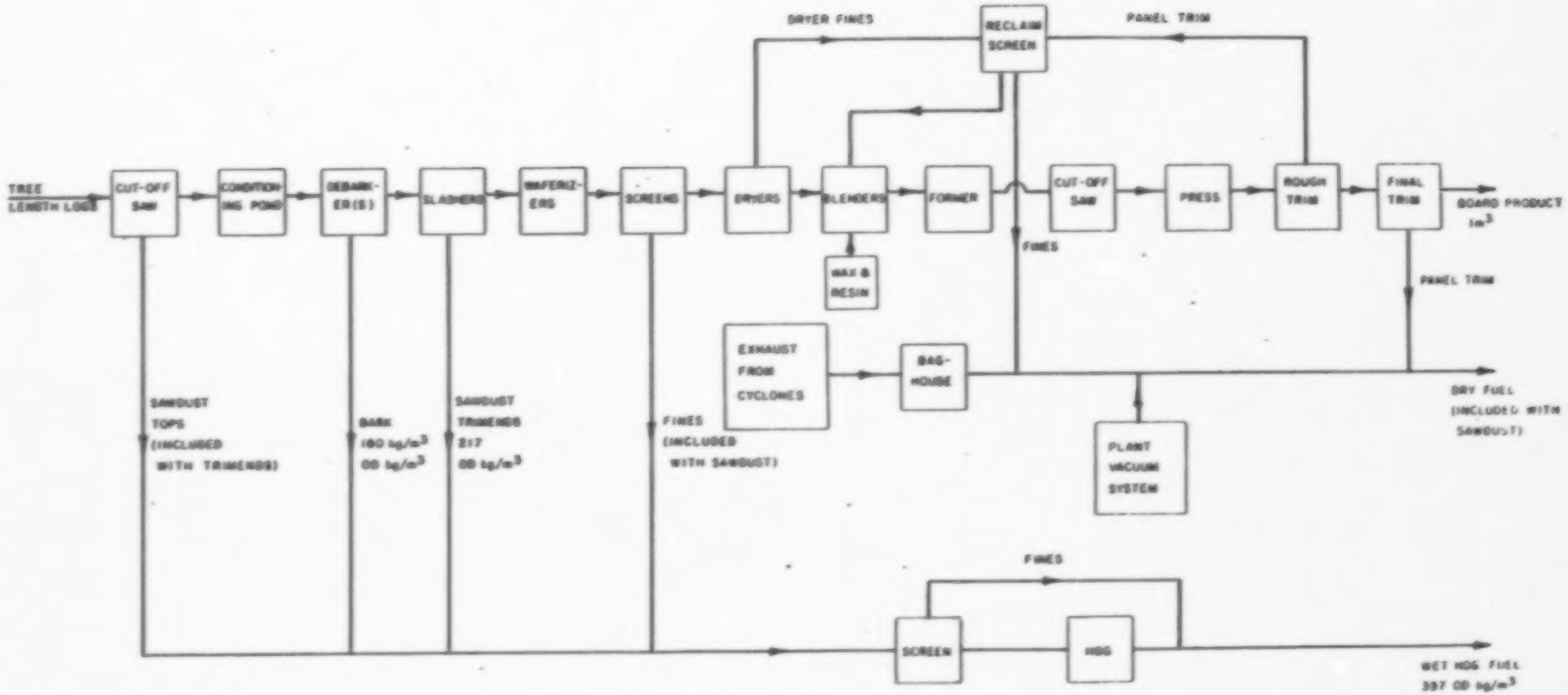

TREE LENGTH LOGS
CUT-OFF SAW
CONDITIONING POND
DEBARKER(S)
SLASHERS
WAFERIZERS
SCREENS
DRYERS
BLENDERS
FORMER
CUT-OFF SAW
PRESS
ROUGH TRIM
FINAL TRIM
BOARD PRODUCT 1m³
DRYER FINES
RECLAIM SCREEN
PANEL TRIM
FINES
WAX & RESIN
PANEL TRIM
EXHAUST FROM CYCLONES
BAG-HOUSE
PLANT VACUUM SYSTEM
DRY FUEL (INCLUDED WITH SAWDUST)
SAWDUST TOPS (INCLUDED WITH TRIMENDS)
BARK 180 kg/m³ OD kg/m³
SAWDUST TRIMENDS 217 OD kg/m³
FINES (INCLUDED WITH SAWDUST)
FINES
SCREEN
HOG
WET HOG FUEL 397 OD kg/m³

Figure 6 - 15

FLOWSHEET OF TYPICAL WAFERBOARD PLANT SHOWING HOG FUEL SOURCES

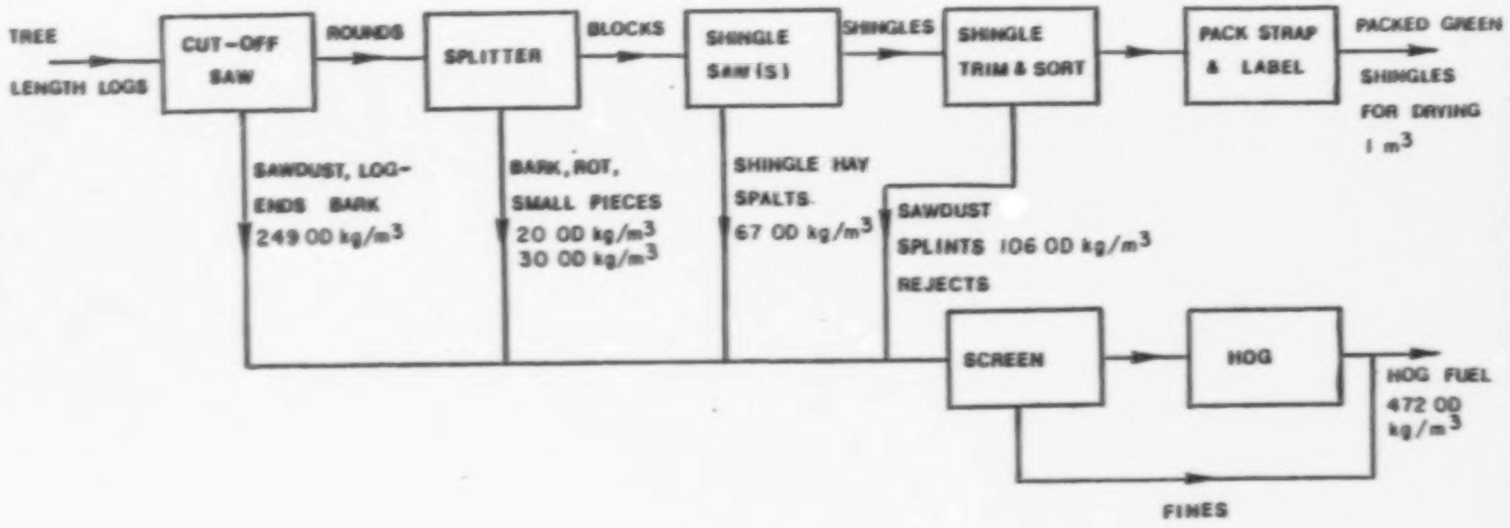

TREE
LENGTH LOGS
CUT-OFF SAW
ROUNDS
SPLITTER
BLOCKS
SHINGLE SAW (S)
SHINGLES
SHINGLE TRIM & SORT
PACK STRAP & LABEL
PACKED GREEN SHINGLES FOR DRYING 1 m3
SAWDUST, LOG-ENDS BARK 249 OD kg/m3
BARK, ROT, SMALL PIECES 20 OD kg/m3 30 OD kg/m3
SHINGLE HAY SPALTS. 67 OD kg/m3
SAWDUST SPLINTS 106 OD kg/m3 REJECTS
SCREEN
HOG
HOG FUEL 472 OD kg/m3
FINES

FIGURE 6-16 FLOWSHEET OF TYPICAL WESTERN RED CEDAR SHINGLE MILL PRODUCING SHINGLES AND HOG FUEL

that this yield could be increased significantly with thinning and fertilization on tree farms.[35] In order to obtain this yield, it is assumed that a dense stand of alder would be produced on a medium quality growing site. To determine the quantity of biomass necessary for a wood-fired thermal plant of the following assumptions were made:

1. Each megawatt (MW) requires approximately 7980 ODt of biomass per annum (80 percent capacity factor and 17 percent overall efficiency).
2. The growing cycle is 10 years.
3. A total of 42 ODt (106 m^3) would be harvested per ha after the 10 years.

These assumptions are based on studies of alder yields which are summarized in Table 6-13. Under optimum conditions poplar yields could be as much as 16 ODt/ha each year in the B.C. Interior. (Fig. 6-17)

(c) Wood Waste Characteristics

Wood waste characteristics were examined in many studies and demonstration projects. Some of these characteristics, and particularly those which relate to B.C. conditions, are summarized in Table 6-14. Table 6-14 includes information on volumes, densities, moisture contents and wood waste/unit of log volume.

The heating values of wood and wood waste are summarized in Table 6-15. The heating values apply to Coastal B.C. and Interior B.C. locations and they are listed for solid wood or sawdust and shavings, oven dry or green, bark or mixed wood waste and for various tree species. This information, together with the information in Table 6-14 and Appendix B, were used in estimating hog fuel availability and hog fuel cost.

(d) Recovery and Processing of Forest Biomass and Mill Waste

Forest biomass or wood waste from the forest, dry land sortyard debris, and mill waste go through six or seven discrete stages in producing hog fuel: recovery, loading, hauling, shearing, barking, chipping or hogging and possibly other processing.

With cable logging systems, the majority of wood waste is found at the landing or within 30 metres of the roads. Wood waste is discarded at the landings for the following reasons:

1. The yarding crews send logs which do not meet specifications.

TABLE 6-13

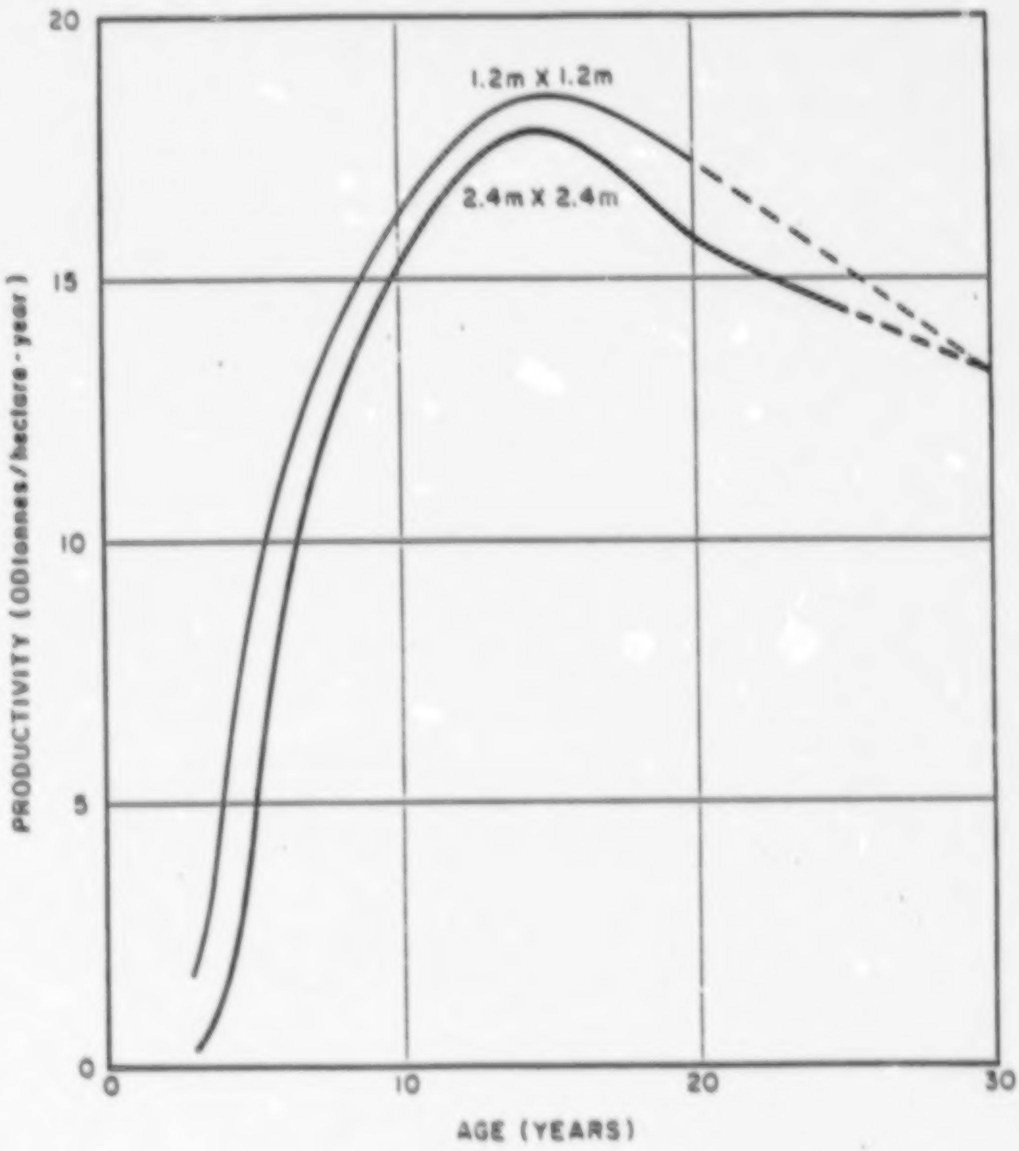
YIELD PER HECTARE, TREES PER HECTARE AND AVERAGE TREE SIZES FOR MEDIUM SITE ALDER STANDS*[1]

Age of Stand Years	Yield/ m^3/ha*[2]	Mean Annual Increment (m^3/ha)	No. of Trees/ha	Average Volume/ Tree (m^3)
10	106	10.6	3,955	0.027
20	199	9.9	1,385	0.144
30	276	9.2	755	0.367
40	327	8.2	505	0.646
50	364	7.3	395	0.920
60	392	6.5	345	1.133

---

*[1] From "Normal Yield Tables for Red Alder" (B.C. Forest Service, 1938).

*[2] Trees 1-inch d.b.h. and larger; recalculated from Imperial units.



REF: EK AND DAWSON, 1976

B.C. HYDRO

FIGURE 6-17

PROJECTED PRODUCTIVITY LEVELS FOR FIRST CROP HYBRID POPLAR, *Populus tristis*

TABLE 6-14

WOOD WASTE CHARACTERISTICS AND COMMONLY USED UNITS*[1]

One unit of solid wood = 2.83 m^3 of solid wood
One m^3 of logs = 0.4904 units of wood chips
One m^3 of solid wood = 2.0 m^3 (approx.) of hog fuel
One volumetric unit (VMU) = 5.66 m^3 = 200 ft^3 (gravity packed)*[2]
One volumetric unit (VMU) = 2.07 m^3 = 75 ft^3 of solid wood equivalent (Coastal B.C.)
One volumetric unit (VMU) = 1.53 green tonnes (Coastal B.C.)
One volumetric unit (VMU) = 1.43 green tonnes (Interior B.C.)
One bone dry unit (BDU) = 1088 OD kg*[3] = 2400 OD lb
One bone dry unit (BDU) = 2.674 m^3 of solid wood (hemlock, balsam, fir, spruce and pine)
One bone dry unit (BDU) = 2.551 m^3 of solid wood (fir, larch)
One bone dry unit (BDU) (cedar) = 3.390 m^3 of solid wood
Oven dry density of hog fuel (cedar) = 636 kg/GPU
Oven dry density of hog fuel (fir) = 955 kg/GPU
Oven dry density of typical Coastal B.C. hog fuel = 855 to 885 kg/GPU
Oven dry density of typical Interior B.C. hog fuel = 778 to 818 kg/GPU
Density of logs (Coastal B.C.) = 0.3833 t (dry)/m^3 (moist)
Density of sortyard wood waste (moist basis - Coastal B.C.) = 400 kg/m^3
Moisture content of sortyard debris (Coastal B.C.) = 55 percent
Moisture content of Coastal B.C. hog fuel = 60 to 65 percent
Moisture content of Interior B.C. hog fuel = 50 percent
Bark as a percent of log volume (Coastal B.C.) = 13
Bark as a percent of log volume (Interior B.C.) = 11
Other non-bark wood waste = 13 to 34 percent of log volume
Sawmill hog fuel production on the South Coast of B.C. = 0.08 to 0.18 GPU/m^3 of sawlogs processed (solid wood)
Material yarded to roadsides = 5 to 10 percent waste
Material hauled to landsort = 5 percent waste

---

*[1] References: 6, 12, 23, 26, 37, 38, 39, 40.

*[2] Equivalent to a gravity packed unit (GPU) and includes both solid wood and air.

*[3] OD is an abbreviation for oven dry.

TABLE 6-15

HEATING VALUES OF WOOD AND WOOD WASTE*[1]

A. General

Gross heating value of Queen Charlotte Island's land sort wood waste = 20.0 MJ/kg d.b. = 7.1 MJ/kg w.b.

Oven dry higher heating value of mixed wood and bark fuels = 19.50 to 22.28 MJ/kg

Oven dry higher heating value of hog fuel = 13.72 to 21.10 GJ/GPU

Oven dry heating value of typical Coastal B.C. hog fuel = 17.94 GJ/GPU

Oven dry heating value of typical Interior B.C. hog fuel = 16.14 GJ/GPU

Oven dry heating value of Coastal B.C. sawdust and shavings = 16.80 GJ/GPU = 7.99 GJ/m^3

Oven dry heating value of Interior B.C. sawdust and shavings = 16.10 GJ/GPU = 7.69 GJ/m^3

One m^3 of solid wood (average) = 8.078 GJ

B. Heating Values of Bark

Tree Species	Heating Value Oven Dry (MJ/kg)
Douglas Fir	23.49
Western Hemlock	22.79
Western Red Cedar	20.24
Black Spruce	20.93
Black Cottonwood	20.93

C. Heating Values of Bark

Coastal B.C. (oven dry) 17.90 GJ/GPU = 8.51 GJ/m^3

Interior B.C. (oven dry) 19.10 GJ/GPU = 9.10 GJ/m^3

TABLE 6-15

HEATING VALUES OF WOOD AND WOOD WASTE*[1] - (Cont'd)

D. Heating Values, Densities and Moisture Contents of Various Tree Species

Tree Species	Green Density (kg/m^3)	Oven-Dry Density*[2] (kg/m^3)	Moisture Content*[3] (%)	Heating Value Oven Dry (MJ/kg)
Douglas Fir	652.33	449.84	45 (coastal)	21.40
True Firs				19.31
Western Hemlock	781.78	422.61	85	19.77
Western Red Cedar	532.34	328.57	62	22.56
White Spruce	571.91	359.65	59	18.84
Black Cottonwood	-	-	-	20.47
Red Alder	743.49	369.90	101	18.61
Broadleaf Maple	-	-	-	19.54
Balsam Fir	741.09	339.94	118	19.31
Sitka Spruce	500.30	349.88	43	18.84
Yellow Cypress	-	420	-	23.03
Lodgepole Pine	-	-	-	20.00
Ponderosa Pine	-	-	-	21.17

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*[1] References: 6, 12, 23 and 39.

*[2] Solid wood.

*[3] Moisture content (%) = 100 $\left(\frac{\text{Weight of Water}}{\text{Weight of Dry Wood}}\right)$
Weight

2. The logs are too short.

3. Portions of the logs are bucked at the landing.

4. There is log breakage during yarding.

Most of the solid wood is found at landings and not at roadside. Therefore, productivity is higher in recovering wood from landings.

Some methods of recovery of wood waste are described in Subsection 6.4 (b). The conventional method of recovering roadside wood waste is by skidder and self-loading logging truck.[41] Forest wood waste is loaded by grapple or self-loading truck, whereas a front end loader is often used for loading sortyard and mill waste.

Transportation of wood waste is often the most costly stage in producing and supplying hog fuel. Transportation of logs in the B.C. Coastal districts is by truck on land or by tug and barge or boom on the sea. Truck transportation of wood waste can be by chip van, container, demolition trailer, gravel truck, self-loading logging truck or highboy four bunk trailer.[37,41] The method depends partly on the state of the material. Large pieces, greater than 2.4 m long, can be handled efficiently by a self-loading logging truck or four bunk trailer. However, mixed wood waste is best handled by container and chips are best handled by using a chip van. Field trials were conducted near Bamfield on Vancouver Island after active logging was completed. A conventional self-loading truck was examined along with three new systems: a highboy four bunk trailer, demolition trailer and containers. The new systems were also tested in conjunction with active logging and used the excess capacity of the log loader to load the wood waste into the recovery units. The utilization standards for the sites were 10 cm diameter tops, 2.4 m lengths and all grades. The haul distance for the trucks was 64 km round trip.

The productivity of the new systems was less than the conventional system, but the cost of the conventional system was higher because of the use of a skidder and crew (Table 6-16). For the new systems the existing yarder and log loader were used without affecting the productivity of their primary logging functions.

The container system had the lowest cycle and delay time of the new systems and it required less space on the landings. However, the capacity of the container system was significantly less and this adversely affected the cost. A longer, larger container without a tailgate could overcome this problem. Removal of the tailgate would also allow the loader operator to see the load and more effectively

TABLE 6-16

SYSTEM COMPARISON*[1]

	Conventional	New Systems		
	Self-Loading Truck	Four-Bunk Trailer	Demolition Trailer	Containers
Number of Days	9	9	2	8
Number of Loads	36	26	7	39
Size of Load (m^3)	20.3	21.8	15.9	10.9
Piece Size (m^3/piece)	0.43	0.68	0.69	0.34
Time per Load (hours)	2.04	2.61	2.03	1.52
Production/Shift (m^3)	79.8	66.6	61.7	57.2
Cost/m^3 Recovered	$15.52*[2]	$9.19	$9.24	$9.62

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*[1] Costs are in 1983 dollars.
*[2] Adjusted to reflect longer haul distance.

distribute it. One truck could be used to alternately haul containers from several landings.

Bark is recovered from sawmill and pulp logs for use as hog fuel. Barking can be done by drum, bag (pocket), ring (rotary), cutterhead, hydraulic or knife barkers.[42] Ring or screw barkers remove bark by turning blades around a log. Drum barkers beat the bark off the log inside a rotating drum. Hydraulic barkers are used exclusively for large diameter logs, whereas, drum, ring and bag barkers can be used for large or small diameter logs. Barkers can be stationary or portable and some can be fed continuously, whereas others can only handle one log at a time. Barkers precede a chipper if pulp chips are obtained from wood waste; otherwise, barkers are unnecessary in hog fuel preparation.

The Paprifer (Pulp and Paper Research Institute of Canada and Forest Engineering Research Institute of Canada) process can be used to separate bark, foliage, rot or grit from chips and can reduce the quantity of potential fuel, but increase the quantity of source material for pulp and paper manufacture.[33] The process relies on vigorous agitation in water to break the wood into small fragments. The wood chips are then washed while passing them over a perforated plate and the refuse falls through the plate. The Paprifer process is suitable for upgrading chips from small-diameter stems, whereas a drum debarker is more suitable for large-diameter material. Further work is required to remove rot from wood waste.

A separator-shearer provides a uniform feed to the hog mill. Sortyard debris consists of bark, branches, logs, slabs, chunks, rocks, metal, sand and water. It is difficult to handle and transport with conventional equipment and is usually discarded in a landfill or by burning, which can be costly and cause environmental problems.[43] The shearer portion cuts the logs, branches and bark into uniform lengths and the separator portion removes the undersize material (<2.54 cm) which contains dirt and water.

Equipment for chipping and pulverizing wood waste for hog fuel can be divided into 5 major classes:[44] chippers, refiners, hogs, shredders and pulverizers. Similarly, debarked logs may be reduced to chip size for chemical pulping. There are three types of chippers: drum, spiral horizontal parallel, or conical disc. Chippers are designed to process logs from short lengths to whole tree trunks. The chips are produced by pressing the logs against a disc or drum shaft which has removable knives. Refiners can process wood chips with a top size of 50 mm. In refiners the wood chips are fed between two closely spaced discs, one rotating and one stationary or two counter - rotating. Hogs process solid wood, bark or a mixture. They cut or crush the wood by the action of knives or hammers which are mounted on a rapidly rotating rotor and act against steel anvil; the product is then screened. Shredders are similar to hogs, but they are designed to process bark. Pulverizers are also similar to hogs, but the knives or hammers act against a baffle or grid bar screen and are designed to reduce pre-hogged wood to fine material.

Typical energy requirements for some common types of wood chippers and pulverizers are listed in Table 6-17.[44] These estimates do not include the energy for auxiliary equipment, conveyors, fans, oil pumps, etc. The energy requirements for wood fuel preparation are affected by wood density, wood moisture content, temperature, final particle size and machine design. Hardwoods require more energy to comminute than softwoods. Energy consumption for chipping, pulverizing and hogging increases with decreasing moisture content. Chipping of dry wood requires 15 to 30 percent more energy than chipping green wood and hogging or pulverizing requires 25 to 50 percent more energy for dry wood than for green wood.[45] Although information is minimal, higher temperatures tend to promote comminution and larger machine sizes require less energy per unit of product. As the particle size is reduced during comminution, additional reductions require disproportionately increasing amounts of energy.

Mobile chippers solve some of the transportation problems. However, most attempts to use logging residues processed by mobile chippers have encountered the following problems:[40]

1. The chips are unsuitable for wood pulp because of the presence of bark, rotten fibre, foliage and dirt, but the chips are suitable for fuel.

2. Chippers produce smooth-sided chips which tend to compact and are less suitable for fuel than the ragged fragments produced by a hogger.

3. Mobile chippers capable of processing logs over 50 cm. diameter must have power units capable of developing more than 370 kW and such a unit is large and expensive.

4. The logging residues are often hard, dry and dirty which increases down time because of wear on chipper knives.

5. The capital cost of mobile chipping equipment is high (approximately $750,000, 1984$).

6. Mobile chippers require skilled operators and readily available maintenance personnel.

7. Chippers do not operate effectively on small, dirty pieces of logging residue.

TABLE 6-17

TYPICAL ENERGY REQUIREMENTS FOR SOME COMMON WOOD CHIPPERS AND PULVERIZERS

A. Chippers and Hog

Chipper or Hog	Nominal Product Size (mm)	Machine Energy Consumption (MJ/ODt) Chipping Parallel to the Grain	Machine Energy Consumption (MJ/ODt) Chipping Perpendicular to the Grain
Chipper[50]	25	5	10
	10	8	17
	5	15	28

Chipper or Hog	Nominal Product Size (mm)	Green Wood 50% Moisture	Dry Wood 20% Moisture	Bark 20% Moisture	Bark 50% Moisture
Hogs or Shredder	75	85-130	65-100	30-50	50-85
	50	90-160	70-120	35-60	60-95
	25	110-210	85-150	40-80	75-125

B. Refiner and Pulverizer

	Inlet Particle Size (mm)	Product Size Distribution Wt.% Retained On 0.66 mm	 0.3 mm	 Wt.% Passing 0.1 mm	Machine Energy Consumption (MJ/ODt)
Thermomechanical Pulping Refiner	10	35.4	20.5	34.0	9,500
	16	31.2	21.4	36.4	10,500

		25.5 mm	22.2 mm	15.9 mm	9.5 mm	4.8 mm	4.8 mm	Machine Energy Consumption (MJ/ODt)
Dry Disc Refiner	Inlet Particles	9	35.2	27.2	35.5	11.9	3.2	
	Product Particles	-	0.3	0.9	26.0	43.0	29.8	65

TABLE 6-17

TYPICAL ENERGY REQUIREMENTS FOR SOME COMMON WOOD CHIPPERS AND PULVERIZERS - (Cont'd)

	Inlet Particle Size (mm)	Product Size Distribution: Wt.% Retained On	Product Size Distribution: Wt.% Passing 3.0 mm	Product Size Distribution: Wt.% Passing 1.5 mm	Machine Energy Consumption (MJ/ODt)
Pulverizer					
Mixed Sawdust, Wood, Bark @ 50% Moisture*[1]	50		100	75	180-220
	50		-	100	290-330

C. Type of Fuel

	Inlet Wt% >11.0 mm	Inlet Wt% 5.5-11.0 mm	Inlet Wt% <5.5 mm	Product Size Distribution: Max Size (mm)	Product Size Distribution: Wt.% Between 5-10 mm	Product Size Distribution: Wt.% Between 1-5 mm	Product Size Distribution: Wt.% Passing 1 mm	Machine Energy Consumption (MJ/ODt)
Mixed Hog Fuel @ 60% Moisture*[2]	50	25	25	25	10	65	25	110

	Inlet Particle Size (mm)	Wt.% Passing 1.7 mm	0.8 mm	0.4 mm	0.2 mm	0.15 mm	Machine Energy Consumption (MJ/ODt)
Wood Shavings @ 20% Moisture*[3]	25-40	100	86	58	22	10	460
Wood Chips @ 20% Moisture*[3]	25-40	86	43	14	5	3	740

	>13 mm	1.6-13 mm	<1.6 mm	4.0 mm	2.4 mm	2.0 mm	1.2 mm	0.9 mm	0.4 mm	Machine Energy Consumption (MJ/ODt)
Hogged Bark @ 40% Moisture*[4]	25	46	29	99	93	89	69	53	23	70

TABLE 6-17

TYPICAL ENERGY REQUIREMENTS FOR SOME COMMON WOOD CHIPPERS AND PULVERIZERS - (Cont'd)

	Inlet Particle Size (mm)		Product Size Distribution			Machine Energy Consumption (MJ/ODt)
			Wt.% Retained On		Wt.% Passing	
	>25 mm	10-25 mm	5-10 mm	1-5 mm	Wt.% Retained on 0.5 mm	
Pine and Birch Bark @ 40-50% Moisture*[5]	30	55	70	90	25-50	125-240

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*[1] Pulverizer is at intermediate point in dryer, so wood waste is warmed before pulverizing.
*[2] Pulverizer is before the dryer, so wood wastes are at ambient temperature.
*[3] Results for a typical hammermill by Dresser-Jeffery.
*[4] 75 percent Aspen and 25 percent Jack Pine.
*[5] Hammermill by F. L. Smith.

Therefore, sortyard processing systems are superior to mobile systems. In either sortyard or mobile systems collection and handling could be reduced in three ways:

1. Bucking at the sortyard rather than in the bush.
2. Yarding, loading and transporting logging residues simultaneously with valuable logs.
3. Sorting pulp, lumber, shake and shingle and logging residue at the sortyard.

(e) Discussion of the Use of Wood or Wood-Derived Fuels

Wood and wood-derived fuels consist of hog fuel and pulp liquor. Only hog fuel is not fully utilized.

The quality of hog fuel depends on species, ratio of bark to solid wood, percentage of rot, exposure to salt water, moisture content, dirt content and piece size distribution. Ultimate analyses of some selected tree species are listed in Table 6-18.

Some of the advantages of using hog fuel for cogeneration are as follows:

1. Improved forest utilization.
2. Solving a disposal problem.

Specific benefits of biomass recovery are the following:[28,37]

1. Less buildup of debris at the loading site which improves the speed and safety of merchantable log loading.
2. Short, small-diameter, but otherwise merchantable logs can be loaded with the debris to improve the loads carried by the regular logging trucks. The short or small diameter, merchantable logs can be recovered at the sortyard.
3. Increases planting productivity (value: $66/ha in 1983$)
4. Decreases need for slash burning.
5. Improves survival of plant stock.
6. Increases forage for livestock.
7. Improves aesthetic values.

TABLE 6-18

ULTIMATE ANALYSES OF SOME SELECTED TREE SPECIES*[1]

	C (%)	H (%)	N (%)	S (%)	O (%)	Ash (%)	Higher Heating Value (kJ/kg)
Douglas Fir	52.3	6.3	0.1	0.0	40.5	0.8	20235
Douglas Fir Bark	56.2	5.9	0.0	0.0	36.7	1.2	21240
Pine Bark	52.3	5.8	0.2	0.0	38.8	2.9	19630
Western Hemlock	50.4	5.8	0.1	0.1	41.4	2.2	19275
Maple	50.6	6.0	0.3	0.0	41.7	1.4	19185
Poplar	51.6	6.3	0.0	0.0	41.5	0.6	19945
For comparison:							
Municipal Solid Waste	47.6	6.0	1.2	0.3	32.9	12.0	19110

*[1] Weight percent on a dry basis.

Ref. U.S. Congressional Office of Technology Assessment 1980. Energy from Biological Processes. Ballinger Publ. Co. Cambridge, Mass.

However, some of the disadvantages of using hog fuel for cogeneration are as follows:

1. Hog fuel is often uneconomical.
2. Extensive collection facilities are required.
3. Quality varies.
4. Supplies are often insecure.
5. Operation and maintenance costs are high.
6. Pollution control can increase costs significantly.
7. The potential for increased removal of plant nutrients from the growing site is a disadvantage of biomass recovery.

Energy applications for wood cannot outbid the forest industry for sawlogs, pulp chips or wood residues for manufacture into forest products. Current and potential uses where demand could increase include softwood pulp chips, hardwood pulp chips, sawlogs, plywood peeler logs, particleboard and composite products.

Most cogeneration in B.C. is in the pulp and paper industry. Pulp and paper production requires substantial quantities of process steam and electricity which are commonly produced sequentially (cogeneration). The steam is generated by the combustion of fossil fuels, organic residues (lignin and hemicellulose) in spent pulping liquors and hog fuel in the form of bark, wood chips and sawdust.[22]

The residues in pulping liquors are a by-product of chemical recovery and constitute a major source of steam energy for the kraft pulping process. Black liquor is a mixture of spent chemicals, lignin and water which is produced during the kraft process. Approximately 1.5 t (±10 percent) of black liquor solids (black liquor with water removed) are produced for each tonne of pulp.[46] The higher heating value of the black liquor solids ranges from 11 630 kJ/kg to 16 280 kJ/kg.

A typical analysis of black liquor from a combined hardwood-softwood cook is listed in Table 6-19.[46] The dry solids from black liquor can consist of as much as 45 percent ash. Moisture, sulphur and sodium in black liquor are high and must be removed before firing. Oxygen is bubbled through the black liquor for stabilization of sodium and sulphur as sodium thiosulphate.

Valuable chemicals are recovered from the black liquor by the combustion process. To prepare for combustion, the black

TABLE 6-19

ELEMENTAL ANALYSIS OF BLACK LIQUOR

	(%)
Carbon	39.4
Hydrogen	3.6
Sulphur	3.4
Sodium	21.2
Inert Mineral Oxides	1.0
Oxygen	31.4

liquor is concentrated by evaporating the water. The black liquor must contain more than 58 percent solids when added to the boiler in order to prevent damage from smelt-water explosions when moist black liquor contacts molten smelt (ash).[46] After burning, the ash is collected, saltcake make-up is added and this material is, in turn, added to the incoming pulp liquor stream to continue the pulping process.

(f) Wood Gasification

Wood gasifiers, such as the one at Ainsworth Lumber in B.C., have not solved the problems of ash removal and gas clean-up.[47] In addition to the gas, both tars and condensible vapours are produced from wood waste and these by-products are not compatible with an internal combustion engine which is commonly used with wood-derived gas. Gas turbines have not operated effectively on combustion products from wood waste because of corrosion and erosion on turbine blades by the ash and salt compounds in the fuel. This problem can be solved by using air which was heated indirectly in a heat exchanger for driving the gas turbine. This method is uncommon, but it should be effective. However, indirect heating reduces the gas turbine inlet temperature and, therefore, the efficiency of the system.

(g) Peat

Peat is a potential fuel for industrial cogeneration, it is commonly used in Ireland, USSR and Scandinavia for power generation and in a few cases for cogeneration. Peat is dead and partly decayed plant material, which has accumulated in a wet environment, where stagnant waters inhibit the circulation of oxygen vital to decomposing organisms. Peat is widespread over the coastal lowlands and in northeastern British Columbia where muskeg is a dominant feature of the landscape. The muskeg contains fibric and mesic peat derived from sedges and sphagnun moss.

Peat is classified using a humification scale established by Von Post;[48] the characteristics of each peat are described in Table 6-20. Better fuel peats are above H5, but peat classified as low as H3 can be used in a thermal plant. Deeper peat is more decomposed and has a higher Von Post index number.

Several characteristics which are important in determining the potential of peat for utilization include density, mineral matter content, moisture content and thickness.[49] The in situ bulk density of peat is dependent on its degree of decomposition and its mineral matter content. The bulk density can range from 48 to 320 kg/m^3.[48] Fibric peat usually contains less than 2 percent mineral matter which results in a lower density. The density of peat increases with increasing decomposition. The water content, when saturated,

TABLE 6-20

SWEDISH GEOLOGICAL SURVEY
METHOD FOR DETERMINATION OF HUMIFICATION OF RAW PEAT SAMPLES
(FROM VON POST 1926)

Humification Scale	Evidence of Degree of Decomposition	Plant Structure	Mud Present	Water Passing	Amount of Peat Substance Passing	Residue
1	Nil	-	Nil	Yes, clear and colourless	-	-
2	Almost nil	-	Nil	Yes, clear but yellow brown	-	-
3	Very little	-	Little	Yes, distinctly turbid, very turbid	-	Not pulpy
4	Little	-	Some	Very turbid	-	Somewhat pulpy
5	Fairly evident	Barely recognizable	Moderate	Moderate amount	Some	Very pulpy
6	Fairly evident	Indistinct less in residue	-	-	One-third	Very pulpy, shows plant structure more than unsqueezed turf
7	Strong	Fairly recognizable	Much	Yes, gruelly and dark in colour	One-half	-
8	Strong	Very indistinct	Much	Yes or no. If if does, gruelly	Two-thirds	Consists of more resistant roots, fibres, etc. in main
9	Almost fully decomposed	Almost unrecognizable	Very much	-	Almost all, as a uniform paste	-
10	Completely decomposed	Entirely without plant structure	Entirely muddy	No free water	All	-

is commonly about 95 percent. If the peat is less decomposed it drains more easily because there is less colloidal peat.[48,49] However, the more decomposed peats are better fuels. Unfortunately, potential fuel peat commonly underlies horticultural peat which must be harvested first. Therefore, a market for the horticultural peat is necessary in order to effectively excavate the fuel peat. A density-moisture curve was derived by Montreal Engineering in a report prepared for Energy, Mines and Resources Canada (Fig. 6-18).[48] Similarly, a heating value-moisture curve was derived in the same report (Fig. 6-19).[48] Most peats are acidic and have a pH ranging from 3 to 6. A peat should be more than 1.8 m thick for satisfactory harvesting.

The advantages of peat are its widespread occurrence, its relatively easy accessibility, low land use values, and low sulphur content.

6.5 MUNICIPAL SOLID WASTE

Municipal solid waste (MSW) is becoming a popular fuel for cogeneration in the United States because of the high cost and environmental unacceptability of landfills. As landfills are closed in British Columbia, an alternate method of disposal will be required and it is expected that there will be a trend toward incineration, possibly with cogeneration and probably in conjunction with hog fuel and natural gas or oil. The constituents of MSW are variable. However, MSW in North America typically consists of the following on a percent by weight basis:

paper products	45%
food and garden wastes	20%
plastic, rubber, textiles	10%
metal	9%
glass	8%
wood, rocks, dirt	8%
Total	100%

The moisture content of MSW varies with the seasons and this affects the heating value which is typically 10.4 MJ/kg. The per capita contribution to the MSW disposal problem averages 1.18 kg/person/day.

The high cost of both inceneration and landfills as well as environmental awareness are encouraging the development of the "3R's" - reduce, reuse, recycle. This development should reduce the quantity of MSW for combustion and could affect the heating value. However, using MSW with other fuels would ensure the security of a fuel supply for a thermal plant.

Another advantage to using MSW as a fuel source is the relationship between MSW availability and the load centre. There is a potential problem in aquiring new rights-of-way into the load

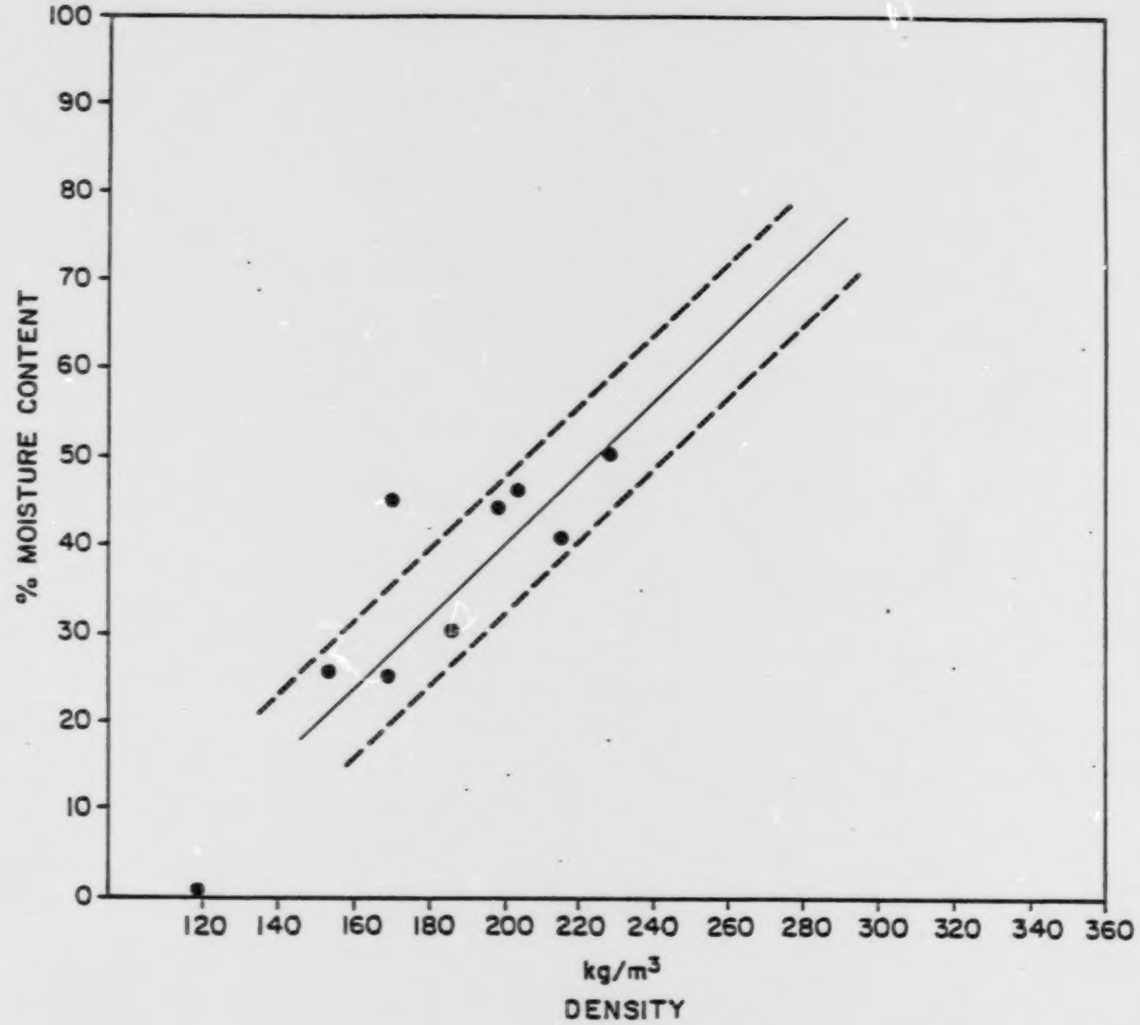

FIGURE 6 - 18

DENSITY/MOISTURE CONTENT OF FUEL PEAT

NOTE: THE POINTS REPRESENT THE CHARACTERISTICS OF A NUMBER OF CANADIAN PEATS

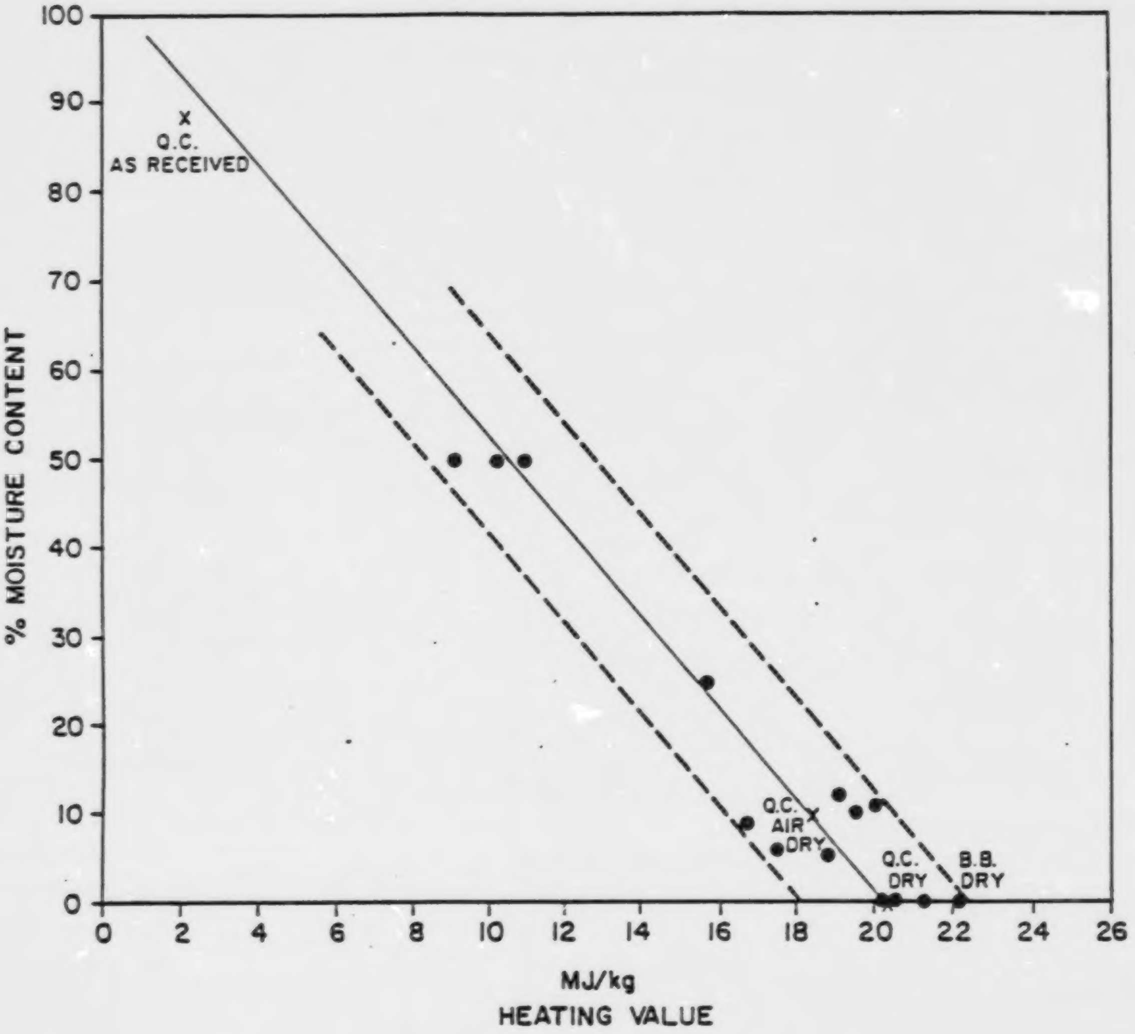

FIGURE 6 - 19

HEATING VALUE/MOISTURE CONTENT OF FUEL PEAT

NOTE: THE POINTS REPRESENT THE CHARACTERISTICS OF A NUMBER OF CANADIAN PEATS

Q.C. = QUEEN CHARLOTTE ISLANDS PEAT
B.B. = CAMPBELL ISLAND PEAT (NEAR BELLA BELLA)

centre. As a result, it is advantageous to build the plant near the MSW (fuel) source and near the load centre.

6.6 NATURAL GAS AND FUEL OIL (FOSSIL FUELS)

Natural gas is popular as a primary fuel for gas turbines outside the forest industry. It is also popular as a primary fuel for kiln dryers and a secondary fuel for power boilers within the forest industry. The popularity is based primarily on its low cost and ease of handling. However, the natural gas price is likely to increase significantly because of increased demand caused by the proliferation of gas-fired cogeneration plants as natural gas becomes the fuel of choice to decrease emissions, smog and global temperature increases.

A recent study completed for B.C. Hydro indicated that the advent of a natural gas supply to Vancouver Island pulp mills may cause natural gas to replace some or all of the hog fuel that these mills now use. Such a shift would result in surplus hog fuel in the Vancouver Forest Region.[4]

Many power boilers use fossil fuels to replace some hog fuel to increase steam production during the winter when steam requirements are highest. Fossil fuels are used in power and recovery boilers under the following additional conditions:

1. Where there is no travelling grate and the firing of hog fuel must be suspended to remove wood ash.
2. Where flame stabilization is required and/or hog fuel is particularly wet.
3. During boiler start-up, when hog fuel is too wet for direct firing.
4. During recovery boiler start-up and turn down for scheduled maintenance.

The degree of replacement of fossil fuels by hog fuel depends on the availability and moisture content of hog fuel, relative costs of fossil fuels and hog fuel, capacity of the power boilers, maintenance schedule of the power and recovery boilers and the ratio of peak to average steam use. The minimum fossil fuel requirement is assumed to be 0.3 GJ/t of kraft pulp production for power boilers with travelling grates and 3.5 GJ/t for power boilers without travelling grates.

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[4] Stewart and Ewing Associates Ltd. 1990. Provincial Wood Waste Supply and Utilization Study Report prepared for B.C. Hydro.

Some pulp mills prefer to use natural gas for steam and electricity generation for the following reasons:

1. Ease of handling.
2. Present reliability of supply.
3. No storage required.
4. Fewer environmental impacts.
5. Lower overall cost of energy produced.

In B.C., these mills are scattered throughout the Lower Mainland, Interior and Prince Rupert areas where natural gas is available by pipeline.

6.7 HEATING VALUES OF "FUEL" SOURCES

The heating values of various "fuel" sources are listed in Table 6-21. Wood waste, natural gas, liquid petroleum gas and residual fuel oil are in common use for cogeneration in B.C. pulp mills.

TABLE 6-21

HEATING VALUES OF "FUEL" SOURCES*[1]

	Higher Heating Value
Natural Gas	37.31 $GJ/10^3m^3$
No. 2 Fuel Oil	38.18 MJ/L
Bunker C-Oil	42.47 MJ/L
Residual Fuel Oil	41.73 MJ/L
Liquid Petroleum Gas (LPG)	26.56 MJ/L
Solid Wood Fuels (average)	8.08 GJ/m^3
Pulp Liquor	14.89 MJ/kg*[2]
Municipal Solid Waste	10.47 MJ/kg
Electricity	3.6 MJ/kW•h

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*[1] References: 19, 22, 23, 46 and 49.
*[2] Derived from a combined hardwood - softwood cook.

SECTION 7.0 - STEAM PRODUCTION, ELECTRICITY GENERATION AND PROCESS STEAM PRODUCTION

7.1 INTRODUCTION

In pulp mills, steam is produced at a pressure which is higher than that required by the process. In steam plant operations, the pressure is reduced by expanding the steam in one of three ways:

1. Through mechanical drive back pressure turbines.
2. Through extraction/back pressure generator drive turbines.
3. Through pressure reducing valves (PRV).

Methods one and two use the high grade thermal energy in the steam at boiler conditions to produce mechanical or electrical power. In the third method, the thermal energy is wasted and this area offers the best opportunity for new cogeneration. Electricity generation is usually favoured because a cycle using mechanical drive turbines is only half as efficient as a cycle which uses electric power for driving equipment. However, in some instances the demand for high or variable speed drives and system security could favour the use of mechanical drive systems.

The steam in cogeneration plants is produced by using a variety of fuels as described in Section 6.0 and illustrated in Figure 7-1. Figure 7-1 applies to the pulp and paper industry in British Columbia where the fuel is used to produce steam in power and recovery boilers. The steam is passed through a condensing or non-condensing turbine to generate electricity or through a mechanical drive to do mechanical work. The low pressure steam is used for process or space heating after passing through a non-condensing turbine, pressure reducing valve or mechanical drive. Black liquor is the most important fuel in British Columbia cogenerating plants and in this section, the utilization of this fuel and hog fuel are described in more detail than other alternatives. Hog fuel is particularly important because black liquor is fully utilized, whereas there is surplus hog fuel in many parts of B.C.

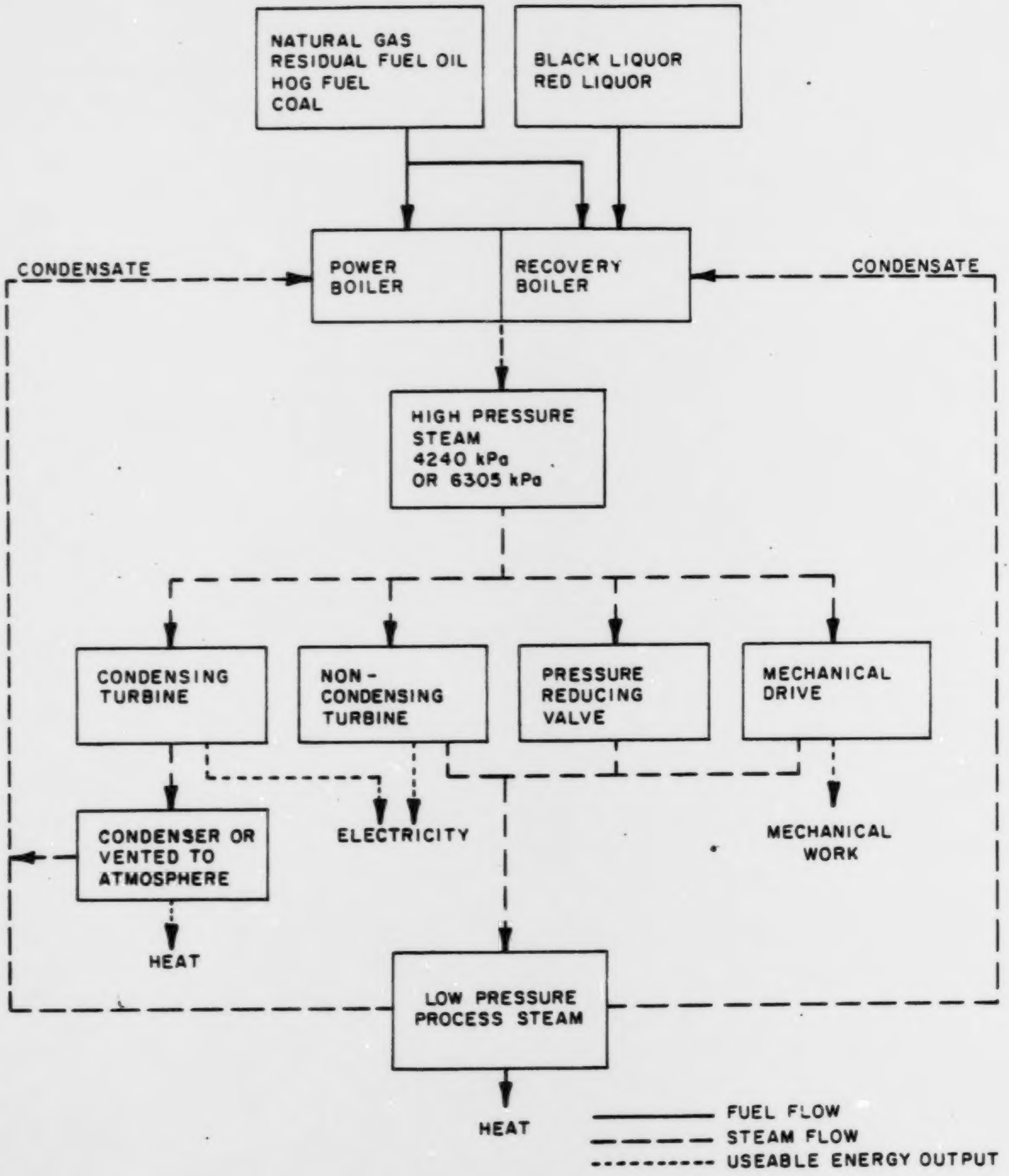
In this Section, black liquor and hog fuel preparation are described. Various methods of black liquor and hog fuel utilization are also described, as well as, the use of other fuels for cogeneration and methods of cogeneration other than steam turbines.

7.2 COMBUSTION OF BLACK LIQUOR

The high moisture content of the black liquor prevents ignition at the liquor gun level.[50] The droplets fall through a reduction zone (air is restricted) onto a porous bed of burning char at the bottom of the furnace, drying, pyrolysing and partially burning as they fall. Inorganic salts are fused in the bed of char and recovered

Figure 7-1

COMMON COGENERATION SYSTEM FOR THE PULP AND PAPER INDUSTRY – FUEL AND STEAM FLOWS AND USEABLE ENERGY OUTPUT


NATURAL GAS
RESIDUAL FUEL OIL
HOG FUEL
COAL
BLACK LIQUOR
RED LIQUOR
CONDENSATE
POWER BOILER
RECOVERY BOILER
CONDENSATE
HIGH PRESSURE STEAM 4240 kPa OR 6305 kPa
CONDENSING TURBINE
NON-CONDENSING TURBINE
PRESSURE REDUCING VALVE
MECHANICAL DRIVE
CONDENSER OR VENTED TO ATMOSPHERE
ELECTRICITY
MECHANICAL WORK
HEAT
LOW PRESSURE PROCESS STEAM
HEAT
FUEL FLOW
STEAM FLOW
USEABLE ENERGY OUTPUT

from the furnace. The primary air is introduced in the drying zone which overlies the reduction zone and is approximately 65 percent of the combustion air. The dried particles rise in the centre of the furnace and they are completely burned in the oxidizing zone which is supplied with secondary air introduced tangentially and approximately equidistant from the top and bottom of the furnace. Both the primary and secondary air are preheated to 149°C in steam-coil air heaters supplied by 50 and 150 psig (445 and 1135 kPa) steam from the mill. Oil or gas-fired burners are used for start-up, shutdown and for low load combustion stabilization.

Black liquor ashes typically have low ash softening temperatures (approximately 788°C) because of high sodium and potassium concentrations.[50] Tangent tube surfaces, appropriately placed sootblowers and widely spaced superheater tubing are used to control slagging in the superheater.

Recovery boilers are subject to corrosion of waterwall tubes when operated at pressures above 4240 kPa (600 psig). A number of methods including compound tubing, multi-coated metallizing, hard-face welding and studs and chrome refractory have been devised to control corrosion, but each of these methods is expensive.

7.3 HOG FUEL DRYERS

The high percentage of moisture in hog fuel impairs the efficiency of the hog fuel boiler in the following ways:

1. The net heating value of the fuel is reduced.
2. Particulate emissions are increased because of incomplete combustion.
3. Higher air flows are required to maintain combustion.
4. The rate of combustion is decreased.
5. The heat flux is reduced because of lower flame temperatures.

Boiler efficiency increases significantly with hog fuel drying because the amount of energy lost in evaporating the moisture, heating excess air and from unburned carbon carry over are decreased (Figure 7-2).[50] Boiler efficiency increases from 46 percent at 65 percent fuel moisture to 74 percent at 40 percent fuel moisture.

For example, reducing the moisture content at MacMillan Bloedel's Powell River plant from about 59 percent to about 47 percent reduces the excess air requirements from 120 percent to as low as 60 percent which, in turn, improves boiler efficiency as indicated in Figure 7-2.[51]

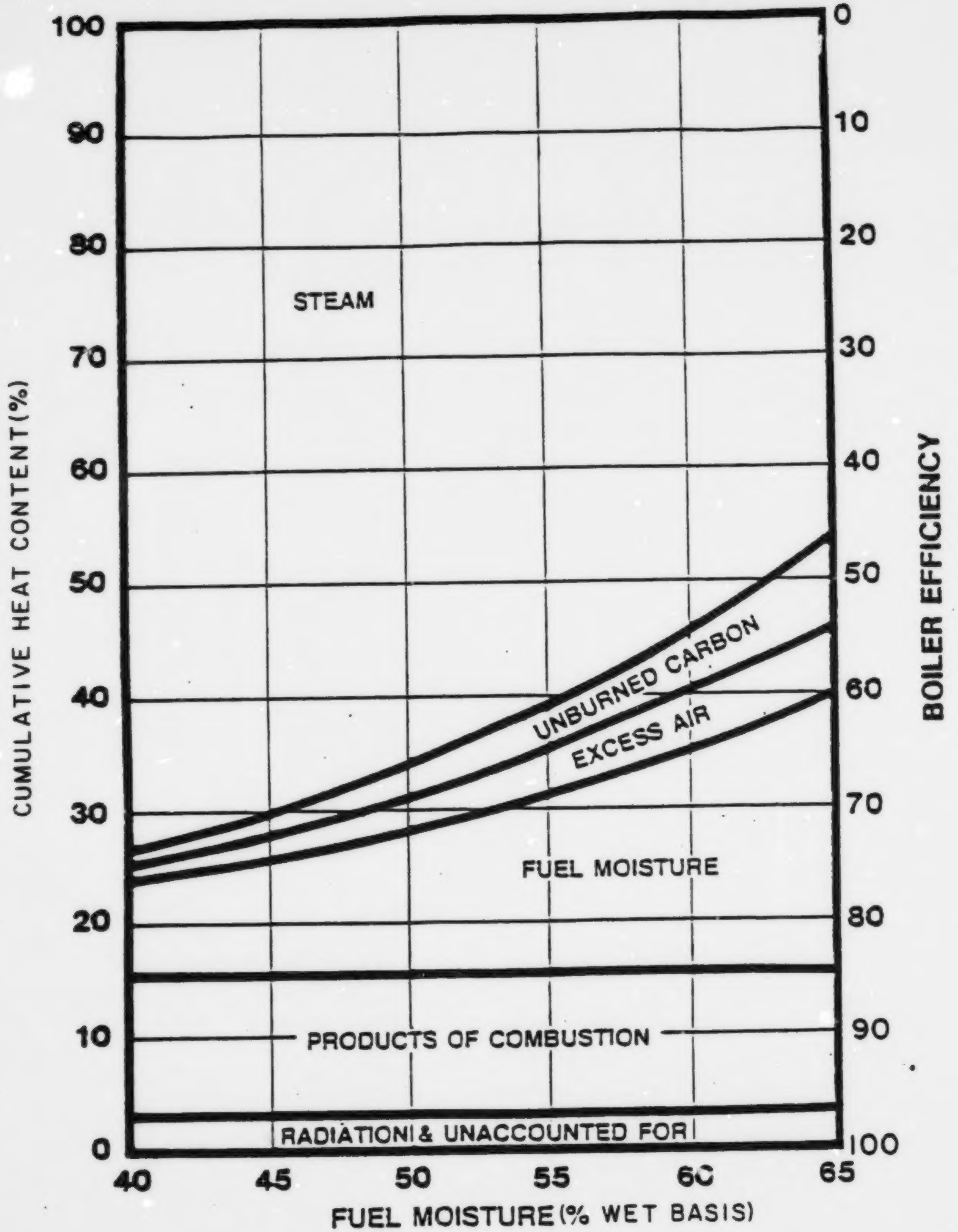


Figure 7-2

THE RELATIONSHIP OF BOILER EFFICIENCY TO THE MOISTURE CONTENT OF THE FUEL

There are two main categories of hog fuel dryers: flue-gas and steam dryers. In a flue-gas dryer the hog fuel is dried by direct contact with the flue-gas which gives up sensible heat to the hog fuel. There are three types of commercially proven flue gas dryers: rotary, cascade and flash dryers. In a steam dryer the steam is used indirectly to provide heat. There are two types of commercially proven steam dryers: shell-and-tube and hot air dryers.

The power consumptions for hog fuel dryers are listed in Table 7-1.[44] These power consumptions include extra energy for blowing gas through flue-gas and hot air dryers and for overcoming the pressure drop in the associated dust collection equipment. The estimates of energy requirements do not include the power consumption for particle size reduction, fans, oil pumps, conveyors, etc.

Vapour recompression drying is a developing technology. With this method the vapours produced by the drying or evaporation process are compressed and returned to the unit to supply most of the heat requirements by indirect condensation. A schematic of the process is illustrated in Figure 7-3.[52] The driving force for heat transfer is the higher condensation temperature of the compressed vapours. Compression ratios are normally kept below two for economic reasons. This limits overall temperature differences to less than 20°C and requires increased heat transfer area. Energy is supplied to the system as electricity and to a lesser extent steam or flue gas. A theoretical net energy gain to a dryer/boiler system using wet hog fuel would be 2.9 MJ/kg of fuel with this system compared with a gain of 0.6 MJ/kg of fuel for flue gas drying. It is predicted that vapour recompression dryers could eventually be economical compared with other dryers and no drying.[51] Simulated vapour recompression drying has been demonstrated in a pilot plant.[53]

7.4 ELECTRICITY GENERATION FROM WOOD RESIDUES

A summary of methods for generating electricity from wood residues are listed in Table 7-2.[2] Only two of these methods, steam turbines and steam engines, are proven technology. Steam engines require wood gasification. All of the technologies can use natural gas.

Steam plants at pulp and paper operations typically include both recovery boilers fired on pulping liquor and multi-fuel power boilers.[19] Supplementary fossil fuels can be used in power boilers to maintain flame stability and increase steam output.

The compatibility of appropriate, proven power systems to forest industry mill types are listed in Table 7-3.[2]

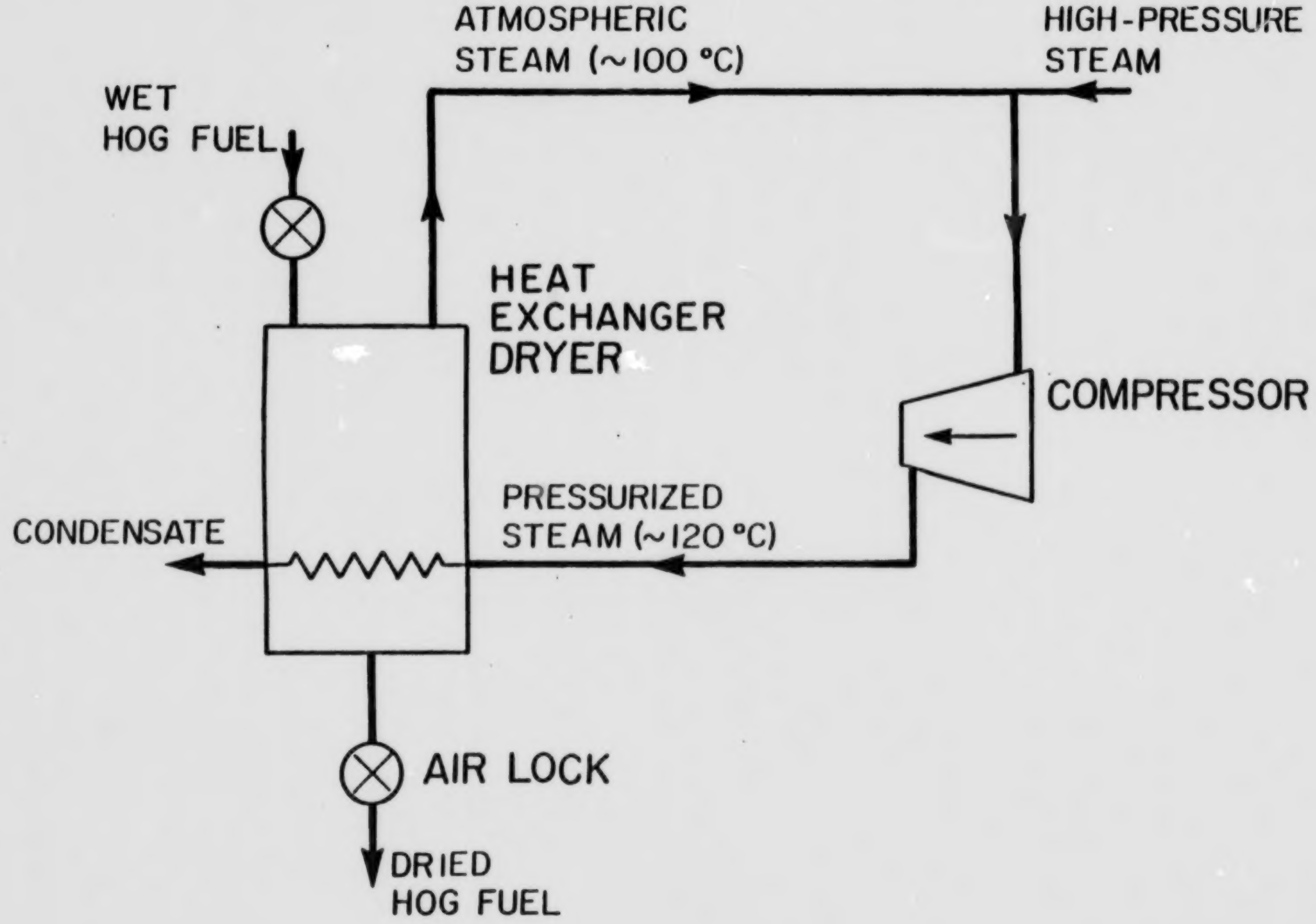

ATMOSPHERIC
STEAM (~100 °C)
HIGH-PRESSURE
STEAM
WET
HOG FUEL
HEAT
EXCHANGER
DRYER
COMPRESSOR
PRESSURIZED
STEAM (~120 °C)
CONDENSATE
AIR LOCK
DRIED
HOG FUEL

Figure 7-3

CONCEPTUAL SCHEME OF A VAPOUR RECOMPRESSION DRYER

TABLE 7-1

TYPICAL POWER CONSUMPTIONS IN WOOD FUEL DRYER SYSTEMS

Dryer Type	Power Consumption MJ/ODt of Wood Fuel
Rotary	50
Cascade	70
Flash	60
Shell-and-Tube	75
Hot Air	65

TABLE 7.-2

PERFORMANCE CHARACTERISTICS AND SELECTION GUIDELINES FOR GENERATING SYSTEMS USING WOOD RESIDUES

PRIMARY CONVERSION/ PRIME MOVER	CHARACTERISTICS	ADVANTAGES	DISADVANTAGES	EQUIPMENT NEEDING IMPROVEMENT	SUITABILITY FOREST INDUSTRY
A. STEAM BOILER:					
1. Steam Turbine					
System Status	- commercial	- Proven equipment with many options - good operating flexibility - worker familiarity - moderate cost - packaged units available	- requires trained operators - needs water source - needs use for steam - high maintenance	- none	- pulp and paper mills - sawmills with dry kilns - plywood and veneer mills
Power Output	>300 kW >1,500 kW typical				
Electrical/ Thermal Energy Output	- 0.04 - 0.45				
Boiler Code	- available				
2. Steam Engine					
System Status	- commercial	- lower steam rates than turbines for sizes below 2 MW - good for variable speed and slow speed applications - good torque characteristics - low maintenance - worker familiarity - good operating flexibility	- limited availability in sizes and options - requires trained operators - needs water source - needs use for steam	- steam engine	- pulp and paper mills - sawmills with dry kilns - plywood and veneer mills
Power Output	- 25 kW to 3,000 kW common up to 2,000 kW possible				
Electrical/ Thermal Energy Output	- 0.04 - 0.45				
Boiler Code	- applicable				

TABLE 7-2 - (Cont'd)

PRIMARY CONVERSION/ PRIME MOVER	CHARACTERISTICS	ADVANTAGES	DISADVANTAGES	EQUIPMENT NEEDING IMPROVEMENT	SUITABILITY FOREST INDUSTRY
B. GASIFIER AND PYROLYSER:					
1. Fuel Cell					
System Status	- demonstration plants operate on natural gas	- no moving parts in fuel cell - low emissions - operating flexibility - modular construction - high efficiency (approx. 42%) over a wide load range	- unproven - no commercial systems available - very sophisticated unfamiliar technology - high cost	- gasifier - gas reformer - fuel cell	- unknown
Power Output	- 200 kW				
Electrical/ Thermal Energy Output	- 1 - 1.2				
Boiler Code	- not applicable				
2. Gas Turbine					
System Status	- conceptual/ research	- suitable for automation - compact - low labour requirement	- best for base load applications - poor part-load performance - operational inflexibility - fouling of turbine common - unproven, limited availability - high maintenance	- gas cleanup - turbine combustor - control - system	- possibly sawmills - speciality products mills
Power Output	- 500 kW to >150,000 kW				
Electrical/ Thermal Energy Output	- 0.2 - 0.8				
Boiler Code	- not applicable				

TABLE 7-2 - (Cont'd)

PRIMARY CONVERSION/ PRIME MOVER	CHARACTERISTICS	ADVANTAGES	DISADVANTAGES	EQUIPMENT NEEDING IMPROVEMENT	SUITABILITY FOREST INDUSTRY
3. Internal Combustion Engine		- suitable for automation - low labour requirement - moderate maintenance - fair equipment availability	- possible problem with engine control due to fluctuations of gas quality - tar and particulate deposits in engine - scrubber water disposal - lube oil contamination	- gas cleanup - control system	- sawmills - special products mills
System Status	- demonstration/ commercial				
Power Output	- 100 kW to 2,000 kW				
Electrical/ Thermal Energy Output	- 0.5 - 0.9				
Boiler Code	- not applicable				
4. Steam Turbine		- tars incinerated, maximizing energy recovery from fuel gas - gas available for other uses - others as per steam boiler	- limited equipment availability - more complex than combustor/boiler combination - others as per steam boiler	- gas burner - steam engine	- pulp and paper mills - sawmills with dry kilns - plywood and veneer mills
System Status	- demonstration/ commercial				
Power Output	- 300 kW to 8,000 kW				
Electrical/ Thermal Energy Output	- 0.4 - 0.45				
Boiler Code	- applicable				
5. Steam Engine					
System Status	- demonstration commercial				
Power Output	- 25 kW to 3,000 kW				

TABLE 7-2 - (Cont'd)

PRIMARY CONVERSION/ PRIME MOVER	CHARACTERISTICS	ADVANTAGES	DISADVANTAGES	EQUIPMENT NEEDING IMPROVEMENT	SUITABILITY FOREST INDUSTRY
Electrical/ Thermal Energy Output	- 0.04 - 0.45				
Boiler Code	- applicable				
C. COMBUSTOR:					
1. Gas Turbine					
System Status	- pilot	- clean gas for turbine - suitable for automation - if closed cycle, good part load performance and efficiency - low to moderate turbine maintenance	- needs a use for hot gas or steam - thermal inertia poses control problem - best for base load, steady operation - limited availability of heat exchanger for high temperature	- heat exchanger - control system	- pulp and paper mills
Power Output	- >500 kW				
Electrical/ Thermal Energy Output	- approx. 0.08				
Boiler Code	- not appli-; cable with combined cycle is applicable				
2. Stirling Engine					
System Status	- prototype/ demonstration	- engine uses isolated working fluid - long engine life - suitable for automation	- ash fouling of heater in Stirling engine - thermal inertia poses control problem - worker unfamiliarity - limited availability	- gas cleanup - Stirling engine	- sawmills - specialty products mills
Power Output	- <40 kW, presently				
Electrical/ Thermal Energy Output	- 0.6 - 1.0				

TABLE 7-2 - (Cont'd)

PRIMARY CONVERSION/ PRIME MOVER	CHARACTERISTICS	ADVANTAGES	DISADVANTAGES	EQUIPMENT NEEDING IMPROVEMENT	SUITABILITY FOREST INDUSTRY
Boiler Code	- not applicable		- small output - small output		
3. Steam Turbine		- hot gases available for other uses - flexible modular system structure - others as per steam boiler	- thermal inertia poses control problem - others as per steam boiler	- steam engine	- pulp and paper mills - sawmills - plywoods and veneer mills
System Status	- commercial				
Power Output	- 300 kW to 11,000 kW				
Electrical/ Thermal Energy Output	- 0.04 - 0.45				
Boiler Code	- applicable				
4. Steam Engine					
System Status	- demonstration/commercial				
Power Output	- 25 kW to 3,000 kW				
Electrical/ Thermal Energy Output	- 0.04 -0.45				
Boiler Code	- applicable				

TABLE 7-2 - (Cont'd)

PRIMARY CONVERSION/ PRIME MOVER	CHARACTERISTICS	ADVANTAGES	DISADVANTAGES	EQUIPMENT NEEDING IMPROVEMENT	SUITABILITY FOREST INDUSTRY
5. Thermionics					
System Status	- research	- no moving parts in converter - good for combined cycle	- unproven - no commercial systems available - high cost - unfamiliar technology - need use for hot gases	- all systems components	- unknown, Electrical/ Thermal Energy output is presently poor for all mills
Power Output	- 4 kW to >100,000 kW				
Electrical/ Thermal Energy Output	- 0.02, presently 0.02 - 0.25, future				
Boiler Code	- not applicable				
D. PRESSURIZED COMBUSTOR:					
1. Gas Turbine					
System Status	- research	- suitable for automation - compact	- thermal inertia of combustor poses control problems - best for base load - ash fouling and wear of turbine - no commercial systems available	- gas cleanup - gas turbine - fuel feed system	- sawmills - specialty product mills
Power Output	- 1,000 kW tested				
Electrical/ Thermal Energy Output	0.2 - 0.08				
Boiler Code	- not applicable				

TABLE 7-2 - (Cont'd)

PRIMARY CONVERSION/ PRIME MOVER	CHARACTERISTICS	ADVANTAGES	DISADVANTAGES	EQUIPMENT NEEDING IMPROVEMENT	SUITABILITY FOREST INDUSTRY
E. PULVERIZER:					
1. Solid Fuel Turbine					
Power Status	- conceptual	- simple system - suitable for automation	- high power required for pulverizing - ash fouling and wear of turbine - no commercial systems available	- all system components	- sawmills - specialty product mills
Power Output	- unknown				
Electrical/ Thermal Energy Output	- 0.2 - 0.8				
Boiler Code	- not applicable				
F. LIQUEFACTION:					
1. Gas Turbine, Internal Combustion Engine					
System Status	- conceptual	- conventional prime movers	- unproven - very low conversion efficiency - high cost	- all system components	- unknown
Power Output	- N/A				
Electrical/ Thermal Energy Output	- N/A				
Boiler Code	- not applicable				

TABLE 7-2 - (Cont'd)

PRIMARY CONVERSION/ PRIME MOVER	CHARACTERISTICS	ADVANTAGES	DISADVANTAGES	EQUIPMENT NEEDING IMPROVEMENT	SUITABILITY FOREST INDUSTRY
G. HEAT RECOVERY BOILER:					
1. Organic Vapour Turbine					
System Status	- demonstration	- recovery of waste heat - higher efficiency than steam below 400°C - best for recovery at 100°C - 300°C	- toxic fluids - problem to handle and dispose of fluids - limited availability of systems - degradation of fluids - worker unfamiliarity	- all system components	- pulp and paper mills
Power Output	- 0.1 kW-1000 kW				
Electrical/ Thermal Energy Output	- does not apply				
Boiler Code	- probably does not apply				
2. Steam Turbine		- See Steam Boiler			
System Status	- commercial				
3. Steam Engine					
System Status	- commercial				

TABLE 7-3

COMPATIBILITY OF CANDIDATE POWER SYSTEMS WITH SAWMILLS, PULP AND PAPER MILLS, AND SPECIALTY PRODUCT MILLS BASED ON THE ELECTRICAL TO THERMAL ENERGY RATIO

	Mill Types		
	Sawmills	Pulp and Paper, Plywood	Specialty Products
Electricity/Thermal	0.1 - 1.0	0.1 - 0.2	0.3 - 1.0
Candidate Systems:			
boiler/steam turbine	Fair	Good	Poor
/steam engine	Fair	Good	Poor
gasifier/gas turbine	Good	Poor	Good
/internal combustion engine	Good	Poor.	Good
/steam turbine	Fair	Good	Poor
/steam engine	Fair	Good	Poor
combustor/gas turbine	Poor	Fair	Poor
/Stirling engine	Good	Poor	Good
/steam turbine	Fair	Good	Poor
/steam engine	Fair	Good	Poor
pressurized combustor/ gas turbine	Good	Poor	Good

7.5 THERMAL TECHNOLOGIES

(a) Introduction

In a thermal electric powerplant the energy of a burning fuel is used to drive an electric generator either directly or indirectly. The prime mover could be a steam engine or a steam turbine, an internal combustion engine (diesel or gasoline) or a gas turbine. As already noted, a range of wood waste fuel is available to the B.C. wood products industry and could be used directly in conventional equipment or converted either mechanically or chemically into a more versatile fuel.[2,54] The use of these converted fuels is generally in the demonstration stage. However, pelletizing, gasification (low Btu gas) and liquefaction (methanol) have promise.

(b) Conventional Thermal

A typical, small, wood-fired, thermal generating plant would have a steam boiler, producing superheated steam to drive a steam turbine which in turn would drive the electric generator. Associated with this equipment would be the fuel storage and ash disposal areas, the fuel and ash handling equipment, a supply of water to provide boiler make-up and condenser cooling, pollution control devices, the electric switchyard, and the necessary operating, maintenance and administration services.

There are three basic methods of burning wood fuel in one of these thermal generating plants: pile burning, fluidized bed burning and pulverized or suspension burning.[54] Despite many similarities, conversion of an existing utility plant to burn wood fuel would require significant modifications.

Pile burning uses fixed reciprocating or travelling chain grates. Pile burning is not suitable for retrofitting a utility boiler because of pressure-part modifications and flue gas capacity. A fluidized bed will accept fuel with variable moisture content, particle size and composition. By putting the furnace next to the boiler, fluidized bed burning would require only modifications of flue gas capacity. Pulverized firing is the most attractive means of retrofitting an existing utility boiler to burn wood fuel. However, the fuel must be fine and dry (e.g. sander dust and pulverized planer shavings from dried lumber). The boiler would be derated, burning openings would be enlarged and ash handling would be added or increased.

The designs for steam boilers differ in boiler tube layout, feeding method and ash removal (Table 7-4).[2] Packaged boilers range in size to a maximum of 45 000 kg/h and modular units range in size to 50 000 kg/h. The use of packaged boilers reduces the cost of field erection. Steam capacities and

TABLE 7-4

TYPES AND CAPACITIES OF STEAM BOILERS

Boiler Type	Furnace Type	Grate Heat Release Limit ($GJ/h-m^2$)	Capacity Range		Typical Steam Conditions	
			Packaged (kg/h)	Field Erected (kg/h)	Pressure (MPa)	Temperature (°C)
Water-Tube	Pile Burning: - Dutch Oven	8.5	---	20,000-90,000	6.2 4.1	480 400
	- Combustion Cells		5,000-34,000	---	1.7-2 4.1	saturated or superheated 400
	- Inclined Grate	10.5	10,000-20,000	30,000-160,000	6.2 4.1	480 400
	Semi-Suspension Burning: - Pinhole Grate	7-11	10,000-30,000	30,000-100,000	6.2 4.1	480 400
	- Travelling Grate	11-13.5		50,000-320,000	6.2 4.1	480 400
	Fluid-Bed Burning	4.2	5,000-45,000	---	1-2 4.1	saturated or superheated 400
		Furnace Heat Release Limit ($GJ/h-m^3$)				
Fire-Tube	Suspension Burning	0.75-1.1	1,000-10,000		1-2.8	saturated or superheated

steam pressure and temperature conditions for steam boilers are also summarized in Table 7-4.

Large furnaces which produce 65 million Btu's (approx. 69 GJ) per hour or more were described in a paper by Elliott (1982) and include the Dutch oven, flat pin-hole grate, steeply sloping pin-hole grate, flat travelling-chain grate and suspension types.[50,55] The Dutch oven furnace was common until recently because of its versatility in handling a variety of fuels and fuel sizes. The largest size for this furnace type was about 100,000 pph (45 450 kg/h steam).

The flat pin-hole grate furnace is essentially a scale-up of the Dutch oven furnace and has a capacity range of 30,000 to 300,000 pph (13 640 to 136 360 kg/h) steam. The flat pinhole grate furnace has two main problems: there is considerable carryover of unburned material and the unit must be shut down for 1 to 3 hours per day for cleaning. These furnaces are being displaced for these reasons.

The steeply sloping pin-hole grate furnace has drying, gasification and burnout zones and is very tolerant of moisture contents as high as 60 percent. This furnace-type is capable of steam capacities of 450,000 pph (204 550 kg/h).

The travelling grate furnace is flexible and can burn wood, coal and RDF (refuse-derived-fuel from municipal solid waste), but maximum particle size is restricted to 75 mm and maximum moisture content is commonly restricted to 55 percent. Modifications by Babcock and Wilcox permit combustion of fuel with a 60 percent moisture content without support fuel. The maximum size is 450,000 pph (204 550 kg/h) steam.

Suspension firing is the most recent system for forest biomass firing. Suspension firing requires a particle size of less than 1 mm and a moisture content of less than 15 percent. Capacities range as high as 1,200,000 pph (545 450 kg/h) steam. The furnace size is small and coal can be burned, but supplementary fuel is not required. Suspension firing can be used in conjunction with a travelling-chain grate.

The range of boiler design capacities affects the choice of furnace type. For example, the travelling grate, semi-suspension design is common for boiler capacities over 160 000 kg/h and is often preferred for boiler capacities as low as 70 000 kg/h.

The performance characteristics of some boiler designs are listed in Table 7-5.[2,56] The relative ratings support the preference for fire-tube designs for low to moderate steam pressures, low capacity, variable output and dry, uniform fuel.

TABLE 7-5

RELATIVE* PERFORMANCE CHARACTERISTICS OF STEAM BOILERS

Boiler Type	History of Service	Compatibility With Wet or Unsized Fuel	Ease and Cost of Operation	Ease and Cost of Maintenance	Steam Pressure Available	Response To Load Change	Turndown Ratio	Capital Cost
Water-Tube:								
- Pile Burning	G	G	G	F	G	P	P	P
- Semi-Suspension Burning	G	F-G	G	F	B	F	F	F
- Fluid-Bed Burning	G	B	G	F	F	G	P	G
Fire-Tube:								
- Suspension Burning	B	P	G	B	F-G	G	B	B

* Ratings are relative to other systems in the same major category: B = best; G = good; F = fair; P = poor.

Source: After Levi and O'Grady

In atmospheric fluidized bed combustion (AFBC), fuel is injected and burned at atmospheric pressure in a fluidized bed of mineral matter such as sand or limestone. The fluidized bed can be circulating, bubbling or spouted. In a circulating fluidized bed (CFBC) the bed of fuel and mineral matter is subjected to an evenly distributed flow of air and the materials become suspended in the gas stream. Eventually the bed becomes turbulent and mixing of particles occurs which result in an efficient combustion process. In a bubbling fluidized bed (BFBC) the air flow is less, so the particles are not suspended. The spouted fluidized bed combustor (SFBC) has a large, centrally located inlet and smaller inlets on the annular region to inject the fluidizing air. It differs from a bubbling bed where the fluidizing air is distributed evenly across the bottom of the bed. The rate of heat transfer in a fluidized bed depends on the following characteristics of the fuel:

1. Mean particle size.
2. Fluidizing velocity.
3. Bed temperature.

Therefore, circulating fluidized beds are generally preferred and installed in new facilities, whereas a bubbling bed may be easier to retrofit. Spouted fluidized beds suffered from slow particle movement. However, inlets at the annular region have eliminated this problem.

Fluidized bed boilers have developed for low to moderate steam pressure, steady output and set fuel applications. Fluidized bed boilers are suitable for high ash and high sulphur fuels and are able to handle stones and tramp materials picked-up in the fuel. They can also handle a range of fuels and changing load conditions in a given installation which offer some flexibility to the operation.

Emissions such as SO^2 and NO_x are controllable by changing the operating characteristics of fluidized bed combustion. The production of SO^2 can be controlled by the injection of limestone into the combustion chamber, and the low combustion temperature in the combustion process (850°C) minimizes the formation of NO_x. It is forecast that the cost of an AFBC unit will be 10 to 15 percent less than a pulverized fired unit with scrubbers. However, the sulphur content of wood fuel is less than 0.1 percent. Therefore, emissions of SO^2 should not be a problem. Similarly, NO_x emissions should be controllable. The advantages of the fluidized bed boiler over the conventional wood-fired boiler are not significant, but fluidized bed combustion could be important with coal-fired boilers. The largest AFBC unit built thus far is a 160 MW coal-fired unit at TVAs Shawnee Power Station.

The next major advancement in this technology is the pressurized fluidized bed which combines fluidizing with a higher interior boiler pressure to permit the use of a combined cycle to improve efficiency. This technology is being developed for coal-fired thermal power generation and a 70 MW plant is under construction.[57]

No matter what type of boiler is installed, the boiler must be flexible in handling variable fuel, process steam and electricity demands. Heat recovery boilers are common in process steam applications in the forest industry and burn either wood or pulp liquors.[2] Heat recovery boilers have fire-tube or water-tube designs. Fire-tubes are limited to steam capacities below 10 000 kg/h and usually produce steam at low to moderate pressures, but can be used to produce steam at pressures as high as 6900 kPa (gauge). Production of high pressure steam (up to 10 300 kPa, gauge) at high flow rates requires the use of water tube boilers.

The efficiency of burning hog fuel in a boiler ranges from 50 to 68 percent depending on wood species, moisture content, excess air, exit gas temperature and carbon carryover.[19,57] A list of approximate boiler efficiencies is summarized in Table 7-6.[23] The equivalent steam production can range from 9.5 to 12.1 GJ/GPU depending on boiler size and moisture content. The overall efficiency of a wood-fired steam boiler/turbine-generator could be as high as 30 percent.[58] With cogeneration, overall efficiency ranges from 60 to 75 percent, depending on the fuel.[59] Approximately 20 to 35 percent of the energy goes up the stack and generator, auxiliaries and miscellaneous steam losses are 5 percent.

Some improvements can be introduced to increase energy recovery and reduce or eliminate the need for supplementary fossil fuel. Older hog fuel-fired boilers require 15 percent fossil fuel "overfire" flame to ensure even burning of the hog fuel.[6] Feedheater additions can be used to increase steam flow without significantly increasing emissions.[19] By increasing the pressure of boilers from 600 to 1250 psig (4240 to 8720 kPa) when delivering steam at 60 psig (515 kPa) to a system, the output of electricity can be increased from 40 kW·h per thousand pounds (455 kg) of process steam to 60 kW·h per thousand pounds (455 kg) of process steam.[60]

In addition to low efficiency, hog fuel-fired boilers have another disadvantage. They must be approximately 3 times larger than oil or natural gas fired boilers for the same steam output for the following reasons:

1. To reduce tube erosion, minimize furnace carryover and reduce stack emissions, furnace velocities for hog fuel-firing are kept at approximately 40 percent of furnace velocities for equivalent oil or natural gas-fired boilers.

TABLE 7-6

"ORDER-OF-MAGNITUDE" BOILER EFFICIENCIES

Energy Source	Boiler Efficiency (%)
Electricity	97
Natural Gas	85
Refined Petroleum Products and Coal	90
Spent Pulping Liquors	55
Hog Fuel	65

2. The volume of hog fuel at 55 percent moisture content is 2.5 times the volume of oil or natural gas at comparable outputs.

The capital cost of a hog fuel-fired boiler is more expensive than an equivalent boiler fired with oil or natural gas for the following reasons:[19]

1. The boiler must be approximately 3 times the size for the same steam output.

2. Fuel preparation is more extensive.

3. Ash handling and disposal are required.

4. Particulate removal from the flue gas is required.

Ignoring fuel costs, operation and maintenance costs for a hog fuel-fired boiler are also higher than comparable costs for oil or natural gas-fired boilers.

As an incentive, to promote energy conservation and efficiency with cogeneration, qualifying plants are permitted a fast write-off of capital costs under the Class 34 category of the Income Tax Act. This allowance applies to equipment only.

(c) Steam Engine

In the steam engine cycle, high pressure steam is expanded to produce a reciprocating piston action which is translated into rotary motion through a crankshaft.[2] Throttling governors and flywheels are used to maintain a constant shaft speed for electricity generation during each revolution and during load changes.[2] The engine can exhaust steam at a back-pressure for process thermal energy or drive a generator and condense the steam with or without extraction.

Steam engines are usually limited by economics to small sizes (<2 MW) at low pressures. Modern steam engines in 25 to 2000 kW sizes have operating pressures between 400 and 15 000 kPa.[2] Between 2 MW and 20 MW each case must be examined to determine whether a steam engine or steam turbine is more economical. The advantages and disadvantages of a steam engine over a steam turbine are summarized in Table 7-7.[2]

Steam rates range from 11 to 28 kg/kW·h for back pressure engines.[2] The steam rate varies with engine efficiency and with steam conditions at the inlet and exhaust. Steam rates for condensing engines range from 5 to 11 kg/kW·h. Condensing engines have thermal efficiencies which range from 14 to 24 percent. The overall thermal efficiency for back-pressure steam engines for producing process heat can be over

TABLE 7-7

ADVANTAGES AND DISADVANTAGES OF STEAM ENGINES OVER STEAM TURBINES

ADVANTAGES:

1. Excellent torque characteristics and easily started under heavy loads.
2. Direction of rotation is easily reversed.
3. More economical than steam turbines in smaller unit sizes (<2 MW).
4. Low maintenance (there can be more than 10 years between major overhauls).

DISADVANTAGES:

1. Requires more space per unit of output.
2. Thermally inefficient.
3. Requires a large flywheel to smooth speed fluctuation during each revolution.
4. Requires internal lubrication.
5. Less economical than steam turbines in larger unit sizes (>20 MW).

80 percent with electric to thermal energy ratios of 0.06 to 0.16.

(d) Gasification

Another method of thermal electric power generation from wood fuel requires gasification of the wood and the subsequent use of the gas in a steam boiler, gas turbine or diesel engine. Gasification of biomass, including processed wood waste or municipal solid waste, has been demonstrated to operate satisfactorily producing a low Btu fuel gas.

Gasification is the decomposition of the long-chain molecules of the wood into products which are flammable.[24] All moisture is expelled during the initial heating. A pyrolysis reaction occurs as more heat is applied to the wood. Then, as the temperature of the fuel rises, the products of gasification (predominantly carbon monoxide, hydrogen and hydrocarbons such as methane and ethylene) are given off. The exact nature and composition of the gases emitted is dependent on the rate and intensity of the heat being applied to the fuel.

In a gasifier, the object is to combine the fuel with as little oxygen as possible, maintaining just sufficient heat to sustain the pyrolysis reaction. Residual carbon is combined with more oxygen (air) and steam to create more gasification product. The combined gasification products constitute a low Btu gas (100 to 300 Btu/scf, i.e. 3725 to 11 180 kJ/m^3) which could be burned in a boiler, reciprocating engine, or gas turbine to generate power.[61] A medium Btu gas could be generated if oxygen were used instead of air in the gasification process. The product gas leaves the gas cleaning equipment at approximately atmospheric pressure and 700° to 800°C.

The heat recovered from a wood gasification system is approximately 80 percent of the heating value of the waste wood input to the gasifier. However, problems still exist in combining the wood gasification technology with engine generation of electric power. Clean-up of the gas and disposal of the oils and tars produced during cooling of the gas are the major problems. Reliability and continuity of operation, without full time supervision, is uncertain because the automated fuel feed and ash removal systems become plugged. These problems could be solved if there was a satisfactory market for the technology. Several gasifiers are commercially available and have been used successfully to generate process heat, particularly for lumber kilns, lime kilns and low pressure steam boilers. Several diesel and gas turbine engine manufacturers have modified engines to burn the low-Btu gas produced by gasifiers.

The fuel gas from gasifiers could be burned in conventional gas-fired boilers. The fuel gas requires special burners to handle the hot gases, and the increased mass flow rate in the boiler causes some derating (to about 70 percent of the nameplate steam rate). While steam boiler/steam turbine technology with low Btu gas is well developed, it is not particularly well suited to small applications (2 MW or less) for the following reasons:[24]

1. A licensed boiler operator is required.
2. Cooling water is required for the condenser (if used).
3. Conversion efficiency to electricity is relatively poor.
4. Capital costs per unit of power generated are high.
5. The overall system tends to be overly large, relative to systems for other solid fuels.

Both spark ignition and dual fuel compression ignition engines have been operated on low Btu gas from biomass gasifiers. The efficiency of reciprocating engines operating on low to medium Btu gaseous fuels is approximately 30 percent. The engines place considerable constraints on the fuel gas quality. The gas must be cooled to nearly ambient temperature. This results in the loss of the sensible heat in the gas, typically 10 to 15 percent of the total energy value of the gas as it exits the gasifier.[24] Further, the gas must be carefully cleaned to remove virtually all of the particulates and tars to prevent abnormal wear and fouling of the engine's moving parts. Thus, even before the gas has been fed to the engine, considerable energy has been lost.

A large investment is required for gas cleaning equipment which tends to be troublesome, and which produces undesirable waste streams. Once the gas is cleaned, it is fed to the engine where its low heating value typically causes reductions in performance (to about 50 to 60 percent of the engine nameplate rating). Some of these losses could be overcome with turbocharging, but there are upper limits even here because of potential auto-ignition problems associated with compressing the gas-air mixture.

In spite of these problems, numerous systems are being tested because reciprocating engines offer the only potentially economical and available power plants suitable for small installations.

Gas turbines offer the opportunity of using low Btu fuel gas at the temperatures and pressures where they are most easily produced. Gas turbines also offer high potential conversion efficiencies.[62] The efficiency of small gas turbines operating close to their rated capacity is approximately 25 percent when using low to medium Btu gas. The conventional open cycle gas turbine configuration offers simplicity, reliability, long lifetime, and compact size. In the open cycle gas turbine, air is compressed and then directed to a burner where fuel is added and burned. The temperature of the gas stream is raised and then the gas stream is expanded through the turbine. The turbine provides power to drive the compressor and the electric generator. Most of the fuel energy is lost as compressor power and as thermal energy in the exhaust stream. Some of the exhaust energy could be recovered with the installation of waste heat boilers. However, the simple open cycle gas turbine would continue to suffer from the following problems when trying to utilize low-Btu gas from a biomass gasifier:[24]

1. Cycle efficiency is low.

2. Gases must be cleaned and cooled before gas compression.

3. Gas compression involves substantial parasitic losses.

4. The large gas flow through the turbine destroys the compressor/turbine match causing losses of performance or requirements for major internal engine modifications.

Some of the disadvantages of the simple turbine could be overcome in the recuperated gas turbine configuration.[24] In this arrangement the compressor discharge is directed to a heat exchanger (termed a recuperator or regenerator) which preheats the compressor air using the turbine exhaust. The preheated air is directed to the burner where fuel is added and the temperature is raised to the final turbine inlet temperature. The recuperator could thus offer a considerable increase in cycle efficiency. However, gas cooling and cleaning equipment would be required and the gas sensible heat and parasitic compressor losses would still exist. For typical components, the parasitic compressor losses could be as much as 30 percent of the engine net power output. Further, the problem of imbalanced flow between the compressor and the turbine still exists.

Other disadvantages of the gas turbine as the prime mover can be overcome by using the downheated or exhaust-fired cycle.[24] In this arrangement, the discharge air from the compressor is heated in the recuperator until it reaches the desired turbine inlet temperature. The hot air is expanded through the turbine to produce shaft horsepower. In this case, the turbine exhaust is just hot air which is used as preheated combustion air for the burner. The burner raises the stream temperature and the gases are then passed over the other side of the heat exchanger. Using this configuration, the lifetime of the turbine hot section is estimated to be 50,000 to 100,000 hours because of the absence of contaminants and corrosive substances in the hot gas stream. Therefore, the reliability of the gas turbine itself is expected to be exceptionally good. The downheated cycle gas turbine offers the following benefits when used with low Btu gas:[62]

1. The overall efficiency is expected to be 21 to 25 percent.

2. Low-Btu gas can be used directly from the gasifier, thus enabling the use of the sensible heat in the gas and the burning of condensible oils and tars in the gas.

3. No products of combustion pass through the gas turbine, thus eliminating many potential turbine problems.

However, there are potential design and operating problems associated with the heat exchanger because of the high operating temperature and the fouling caused by the ash in the combustion gases. At this time the high cost of the heat exchanger is a major drawback to wide-scale application of the downheated turbine cycle. Some engine generator control problems are also expected. However, the generation of electricity from biomass in gasifiers and engine generators is a developing technology which holds promise.

(e) Peat Utilization

The peat deposits in Canada represent a significant energy source, but there is no significant peat-fired steam generation in this country. However, the technology is well developed in Europe, primarily in Russia, Ireland and Finland where it is used as a fuel for the generation of electricity. While the use of peat as a fuel presents many design and operating problems it can be considered as an alternative if coal is not readily available.

The moisture content of peat is one of the most important properties affecting its utilization in thermal powerplants. When air dried to 50 percent moisture, peat typically has a heating value between 9300 and 11 600 kJ/kg.[24] The sulphur content of peat is very low and the ash content varies considerably, from 2 to 70 percent of the dry peat, depending on the water supply to the peat bog. If the water comes mainly from precipitation the ash content is low. If the bog is periodically flooded by surface water, sediments will significantly increase the ash content of the peat.

Handling of peat poses some special problems. If the moisture content falls below 40 percent, there is the danger of spontaneous combustion of explosive dust mixtures and the nuisance of dust.[24] If the moisture content is above 55 percent the peat bridges in storage bins and chutes, and freezes when the ambient temperature is low.

The properties of peat, such as particle size, moisture and ash content, have a significant effect on boiler design. Furnace size is primarily determined by two factors:

1. Residence time required to ensure complete combustion.
2. The size of radiant heat absorbing surfaces sufficient to minimize slagging and fouling.

In general, furnace sizes for peat are much larger than for comparable coal-fired units. Air heaters require careful design to avoid plugging and to provide the high combustion air temperature necessary for stable combustion of the high moisture fuel.

Particulate removal from the flue gas must be effective. In general, the sulphur content of peat is so low that SO_2 emissions are not a problem. While fuel nitrogen is similar to many coals, peat has high volatiles and is amenable to low NO_x-firing techniques. The high moisture content of peat tends to limit flame temperature in the furnace to a level where thermal NO_x formation is insignificant.

New methods of peat utilization through gasification and/or liquefaction are being examined in the USSR, Finland, Sweden, United States, Canada and Israel. Many of the processes could be operated to favour either gases or liquids, the latter under less severe operating restrictions. Based on hydrocarbon gas yield, peat is appreciably more reactive than lignite in the gasification process.[48] The reactivity is probably related to the higher volatile matter in addition to other unknown factors.

In Canada, Quebec Hydro has concluded that a 0.75 MW generating station fired on gasified peat is feasible; a gasification plant is proposed for Anticosti Island using "pyrolysis" in limited air.[63] The University of Sherbrooke and Beak Consultants have demonstrated the technical feasibility of producing bitumen from peat by using heat and catalysts in a reactor vessel. The bitumen could be used in oil-fired burners with little upgrading. In the future, peat gasification could provide fuel for a thermal plant where more economical alternatives are unavailable.

7.6 STEAM TURBINES

(a) Introduction

Steam turbines can be classified using a number of features. Single stage steam turbines are restricted to 2.5 MW or less, whereas multiple stage steam turbines are 1.5 MW or larger.[2] Other methods of classifying steam turbines are described in the following sections in some detail.

(b) Topping and Bottoming Cycles

The wood products industry uses electric energy and thermal energy. Figure 7-4 is a schematic illustrating a conventional process without heat recovery.[2] However, the wood products industry commonly uses cogeneration to supply energy for its process. There are two fundamental types of cogeneration cycles: topping cycles and bottoming cycles.

With a topping cycle, electrical or mechanical energy is produced first and thermal energy is subsequently obtained from the exhaust (Figure 7-5). Topping cycles are the most common type of cogeneration cycle and are used with steam turbines, gas turbines, diesels or fuel cells. Cogeneration plants in the forest industry use a topping cycle. In this industry steam produced in the boiler is expanded through the turbine, thereby producing electricity at the generator. Low pressure steam discharged from the turbine is piped to the process.

With a bottoming cycle, thermal energy is obtained from a waste stream and is subsequently used to produce electricity (Figure 7-6).[2] Bottoming cycles use Rankine-cycle turbines to produce shaft power from steam or from an organic fluid. In a Rankine cycle the working fluid is heated and vaporized in a vapour generator at constant pressure then expanded in a turbine or steam engine (Figure 7-7). The expander exhaust is cooled at constant pressure, then pressurized and returned to the expander. Thermal efficiencies range from 14 to 36 percent. Rankine cycle systems are usually more than 500 kW in power output.

The complexity of Rankine cycle steam turbine generators increases with output capacity. Systems with less than 5 MW of capacity must be of simple design for reasons of economy.[2] Therefore, they cannot incorporate features such as high and low pressure turbines to maximize thermal efficiency. Rankine cycles are usually categorized according to their use of a back pressure or condensing turbine.

The availability of bottoming cycles is dependent on the combustion temperature of the fuel. A combustion temperature of about 870°C will produce an exhaust gas temperature of about 345°C and a combustion temperature of about 1205°C will produce an exhaust gas temperature of 660°C. This is the range applicable to bottoming cycles. Bottoming cycles are used for industrial processes, such as the mineral industry, that require high temperatures in the order of 870°C to 1200°C. Waste heat at 340°C to 650°C is used to raise steam for a steam turbine. The waste heat can also be used in waste heat boilers to raise steam and drive steam turbines in the bottoming process.

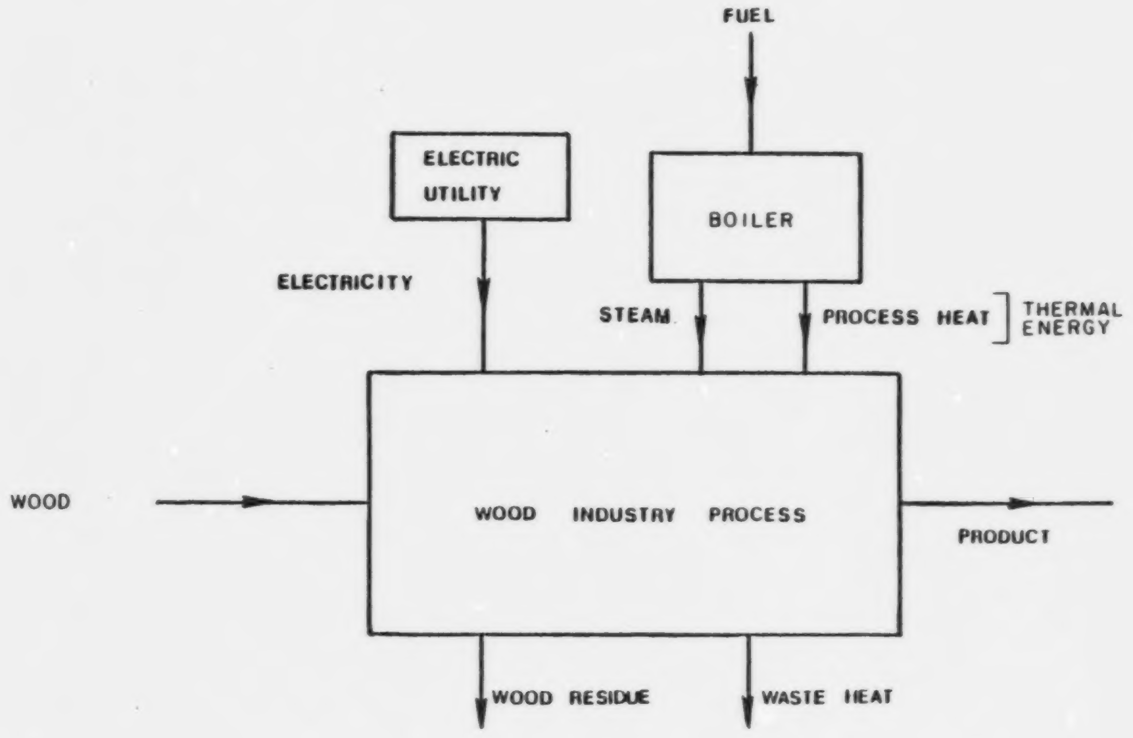

FUEL
ELECTRIC UTILITY
BOILER
ELECTRICITY
STEAM
PROCESS HEAT
THERMAL ENERGY
WOOD
WOOD INDUSTRY PROCESS
PRODUCT
WOOD RESIDUE
WASTE HEAT

FIGURE 7 - 4 CONVENTIONAL PROCESS WITHOUT RESIDUAL ENERGY RECOVERY

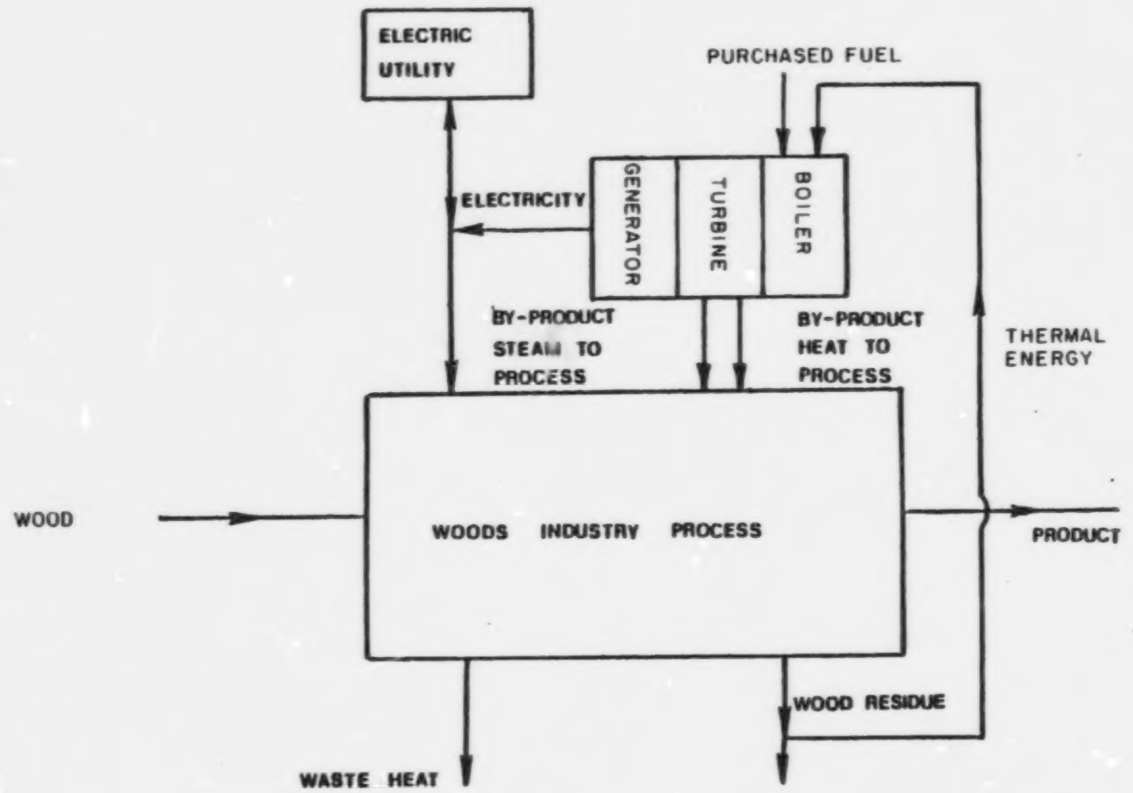

ELECTRIC UTILITY
PURCHASED FUEL
ELECTRICITY
GENERATOR
TURBINE
BOILER
BY-PRODUCT STEAM TO PROCESS
BY-PRODUCT HEAT TO PROCESS
THERMAL ENERGY
WOOD
WOODS INDUSTRY PROCESS
PRODUCT
WOOD RESIDUE
WASTE HEAT

FIGURE 7 – 5 COGENERATION USING A TOPPING CYCLE

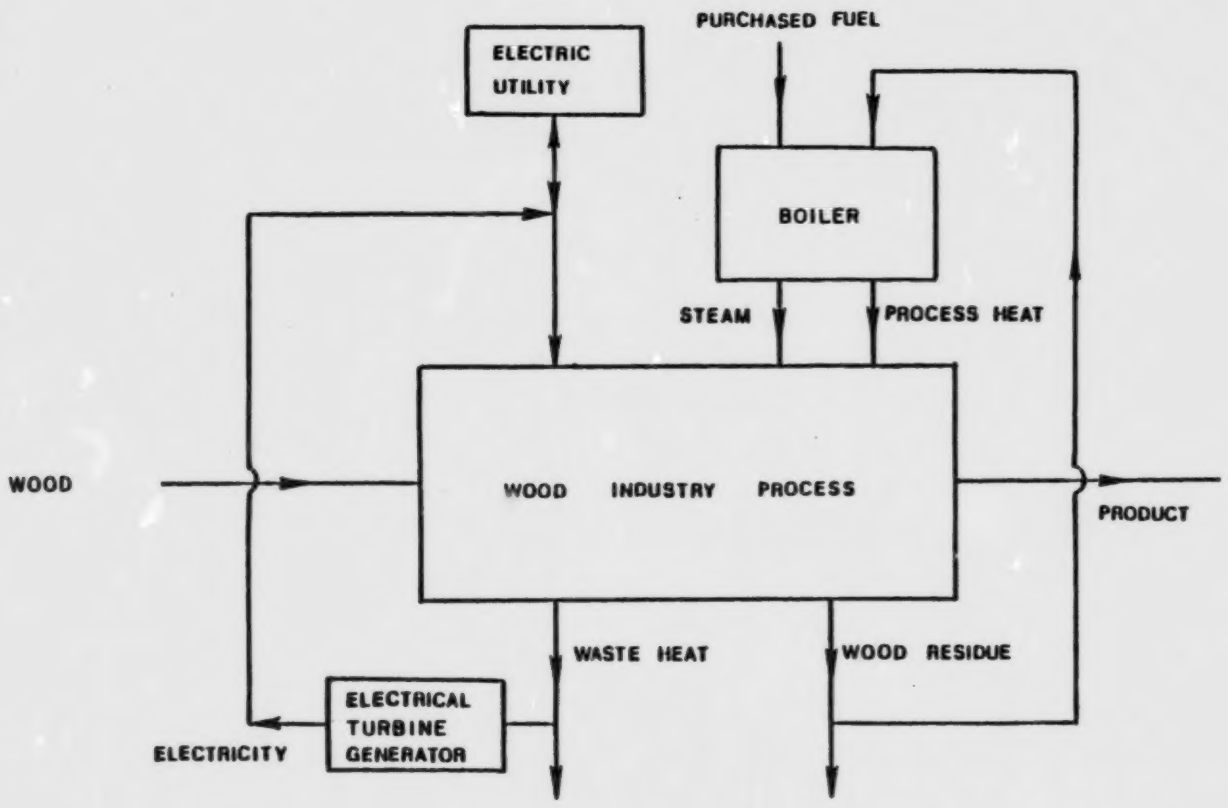

PURCHASED FUEL
ELECTRIC UTILITY
BOILER
STEAM
PROCESS HEAT
WOOD
WOOD INDUSTRY PROCESS
PRODUCT
WASTE HEAT
WOOD RESIDUE
ELECTRICAL TURBINE GENERATOR
ELECTRICITY

FIGURE 7-6 COGENERATION USING A BOTTOMING CYCLE

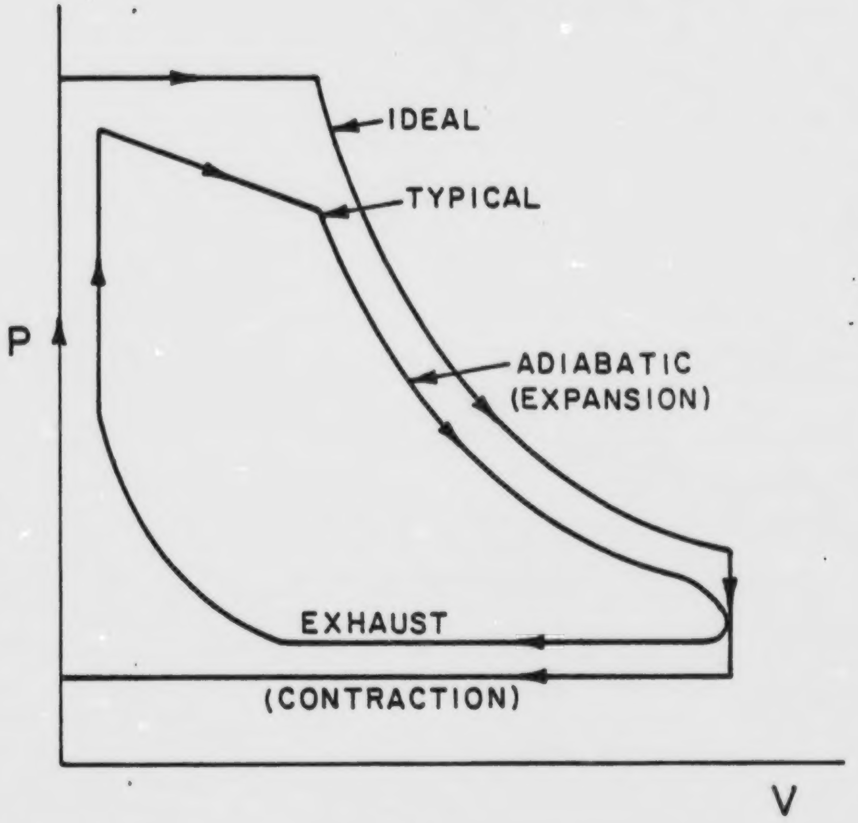

IDEAL
TYPICAL
P
ADIABATIC (EXPANSION)
EXHAUST
(CONTRACTION)
V

Figure 7-7

RANKINE CYCLE STEAM ENGINE
P - V DIAGRAM

It is also possible to combine bottoming and topping cycles as illustrated in Figure 7-8.[2] Electricity generation occurs both before and after the extraction of process heat.

(c) Condensing and Back Pressure Steam Turbines

Steam turbines can be classified according to the availability of steam extraction, location of steam extraction and general steam flow pattern.

Condensing steam turbines are equipped with condensers, so they can exhaust steam at sub-atmospheric pressures. Condensing steam turbines with steam extraction have more flexibility because changing the steam supplied to the process does not affect electrical output and vice versa, but they cost considerably more. In a conventional thermal plant, without cogeneration, approximately 45 percent of the energy in the high temperature, high pressure steam is rejected to the surroundings when the steam is condensed, approximately 20 percent goes up the stack and approximately 10 percent is used for plant operation and lost through generators and auxiliaries.[59] The use of condensing turbines and an increase in the pressure/temperature at the turbine inlet favour the production of electricity.[2]

In a back pressure turbine, process steam is extracted at the last stage and at higher than atmospheric pressure. The back pressure steam turbine makes use of the pressure drop between the steam boiler and the process side (e.g. 4130 kPa (gauge) at the boiler to 1000 kPa (gauge) at the process).[60]

Power output varies significantly with fuel type, boiler steam flow, boiler pressure and extraction pressure. Examples of plots of power output for an extraction/back pressure turbine installed in an oil- gas-fired cogeneration plant are illustrated in Figs. 7-9 and 7-10.[19] One example assumes 150/50 psig (1035/445 kPa) process steam pressures and the other is an example of a back pressure turbine assuming a 50 psig (445 kPa) process steam pressure.

(d) Turbine Stream Flow Patterns

Steam turbines can also be classified by their steam flow pattern into straight-flow, extraction, induction and combination-flow turbines. Straight-through turbines use a full throttle steam flow from inlet to exhaust (Figure 7-11).[2] Extraction turbines have one or more locations where intermediate pressure steam can be withdrawn from the turbine to meet multi-pressure process steam requirements (Figure 7-12). Induction turbine operation is opposite to the operation of an extraction turbine. Steam at less than throttle pressure is injected into the turbine downstream of the inlet in order to generate additional power (Figure 7-13). Some turbines combine extraction and induction and the

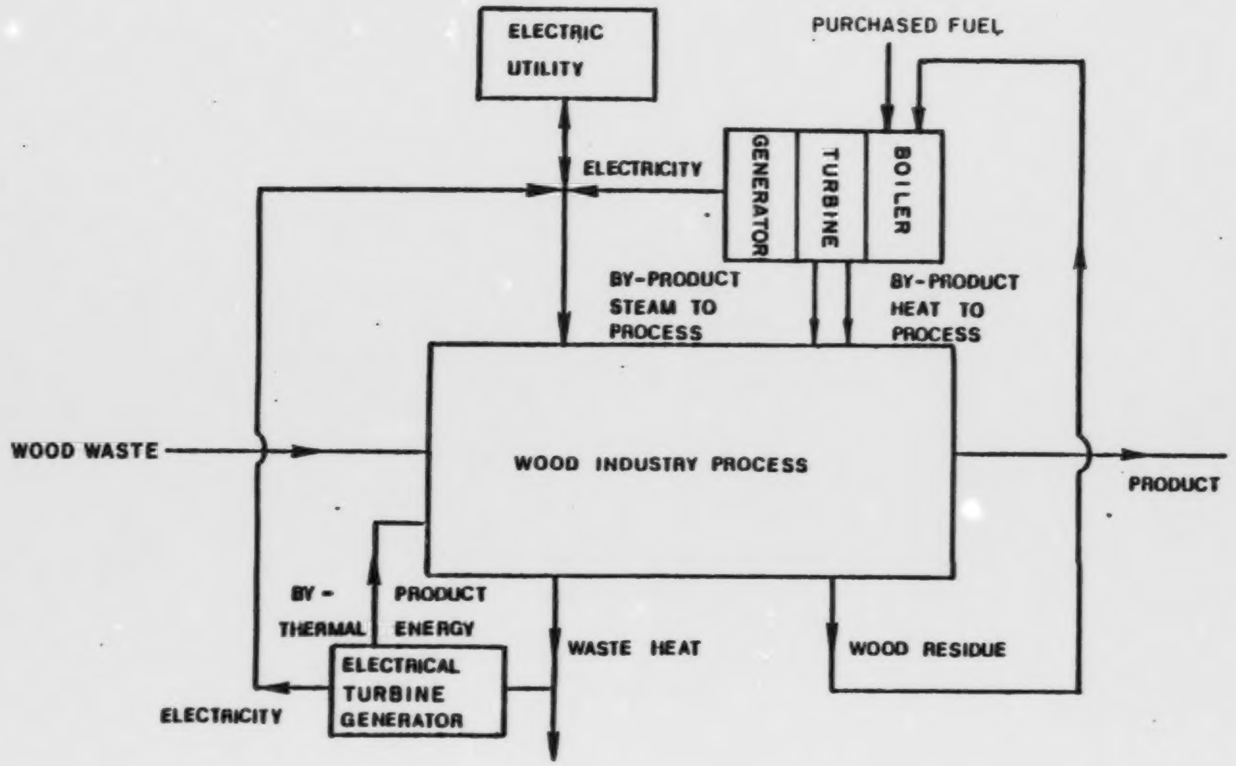

ELECTRIC UTILITY
PURCHASED FUEL
ELECTRICITY
GENERATOR
TURBINE
BOILER
BY-PRODUCT STEAM TO PROCESS
BY-PRODUCT HEAT TO PROCESS
WOOD WASTE
WOOD INDUSTRY PROCESS
PRODUCT
BY - THERMAL
PRODUCT ENERGY
WASTE HEAT
WOOD RESIDUE
ELECTRICAL TURBINE GENERATOR
ELECTRICITY

FIGURE 7-8 COGENERATION USING BOTTOMING & TOPPING CYCLES

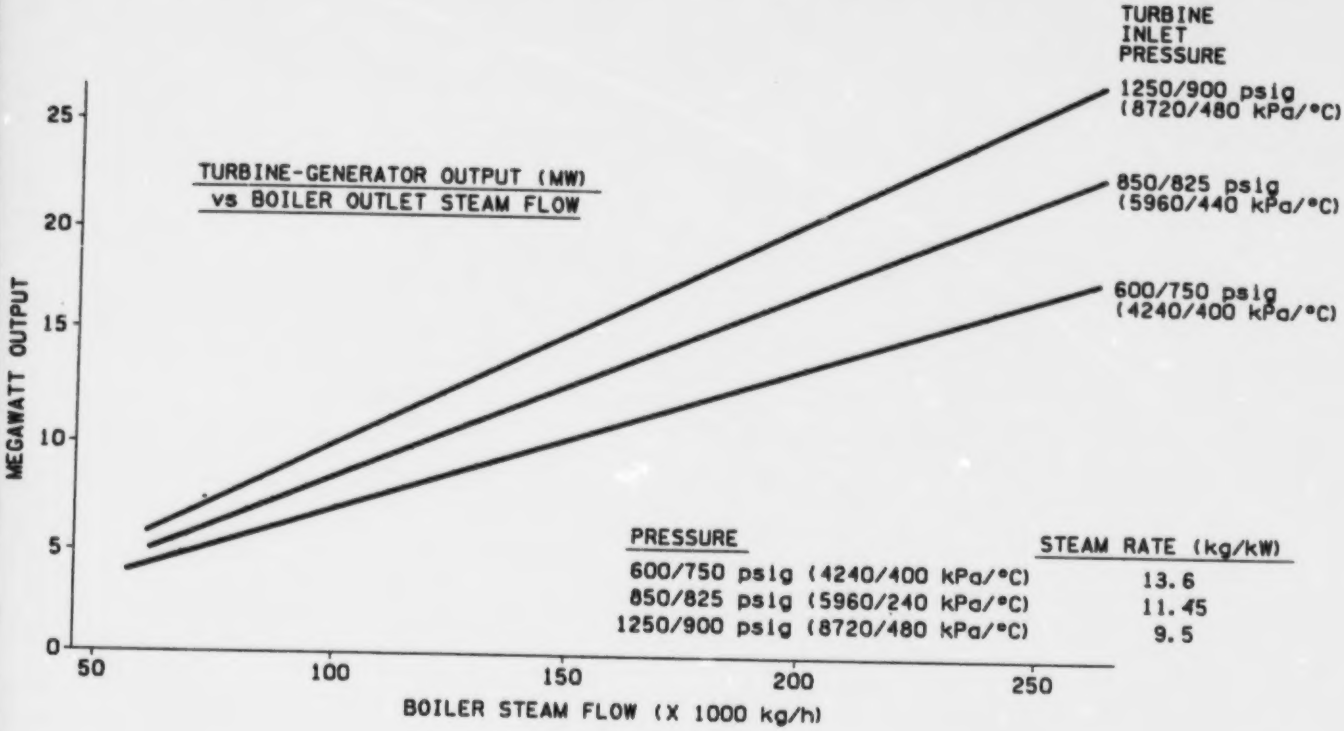


Figure 7 - 9

OIL-GAS FIRED COGENERATION PLANT
150/50 PSIG EXTRACTION/BACKPRESSURE
TURBINE GENERATOR

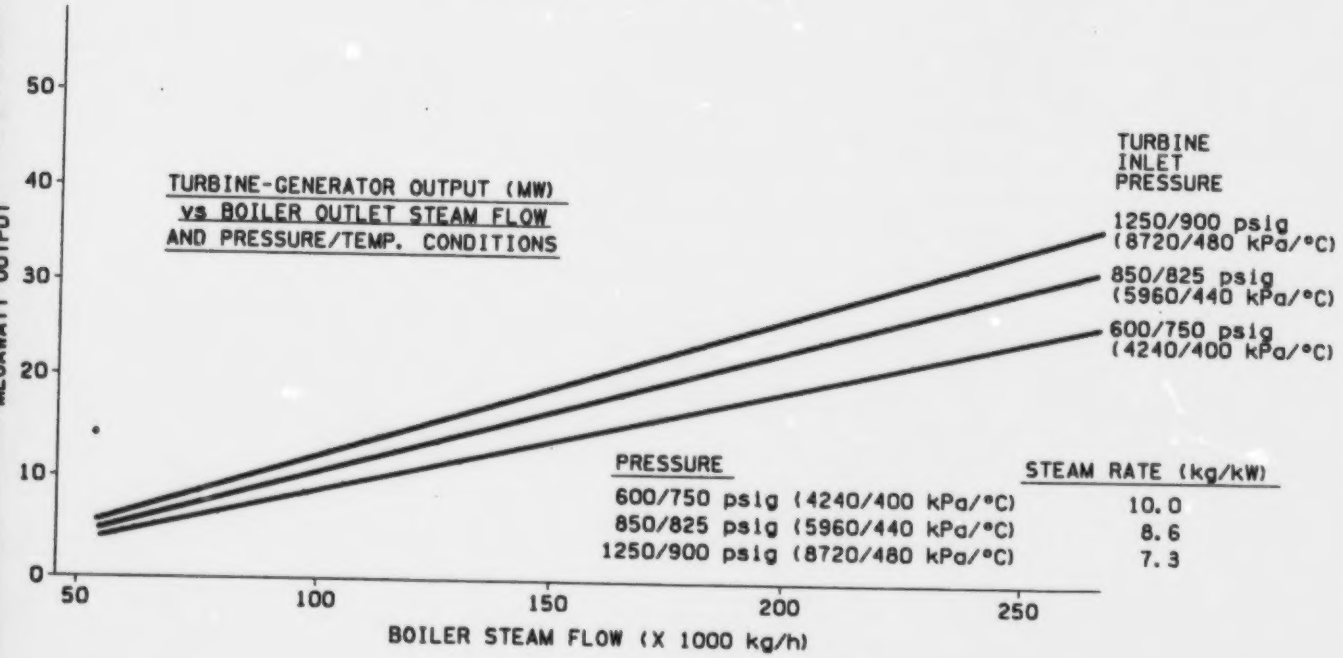


Figure 7 - 10

OIL-GAS FIRED COGENERATION PLANT
50 PSIG BACKPRESSURE
TURBINE GENERATOR

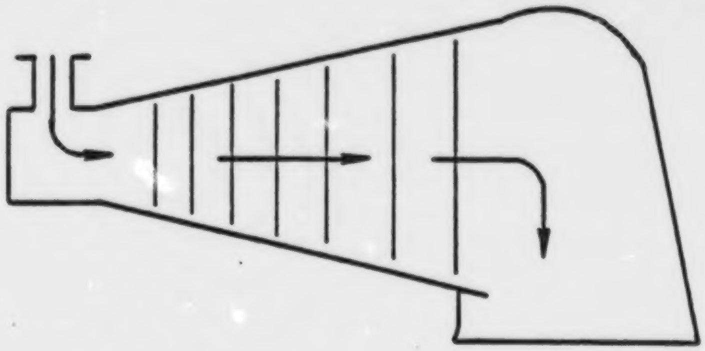


Figure 7-11

STRAIGHT-THROUGH FLOW TURBINE

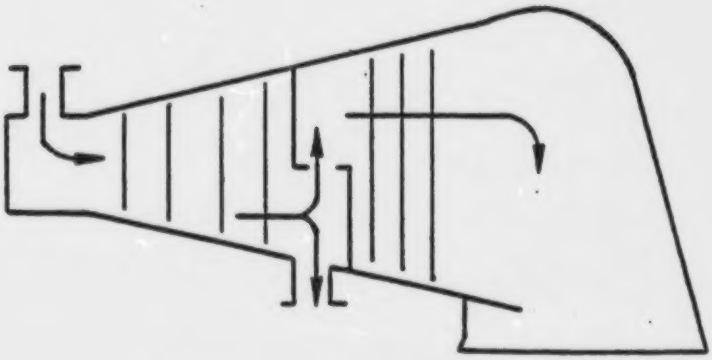


Figure 7-12

EXTRACTION FLOW TURBINE

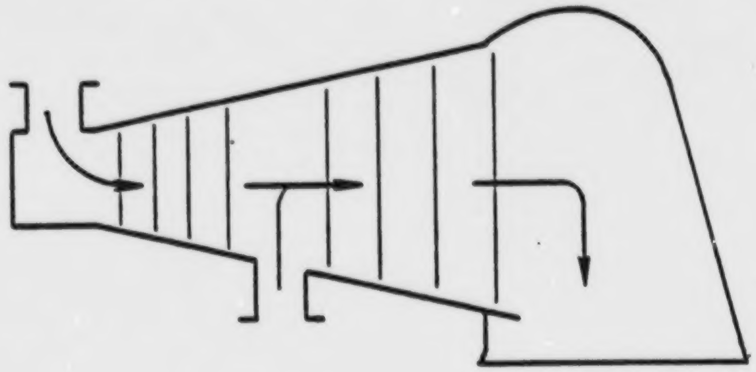


Figure 7-13

INDUCTION FLOW TURBINE

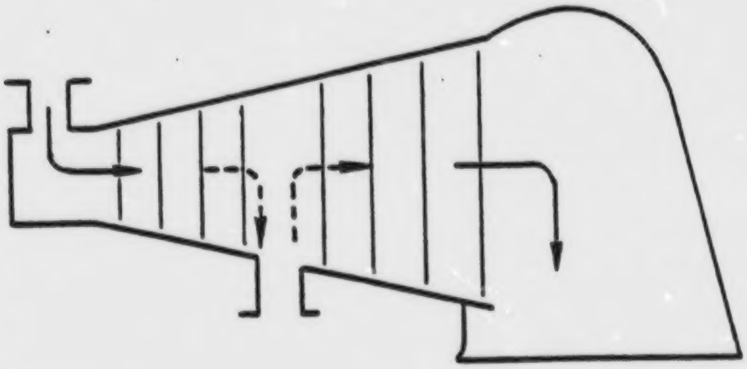


Figure 7-14

COMBINATION FLOW TURBINE

intermediate steam is kept at constant pressure by extracting or admitting steam as required (Figure 7-14).

Steam turbines have both back pressure extraction/noncondensing and extraction/condensing configurations. As noted in the previous subsection, back pressure turbines are steam turbines that exhaust steam at temperatures and pressures suitable for process heat applications. Extraction/noncondensing turbines allow for extraction of high pressure steam from an intermediate port and for extraction of exhaust steam.

Extraction/condensing turbines are versatile in permitting wide variations in steam and electric loads. Power-to-heat ratios for these steam turbines range from approximately 28 to 70 kW·h/GJ.[42] Full-load electric overall efficiencies for wood-fired plants range from 14 to 28 percent and 50 percent part-load overall efficiencies range from 12 to 25 percent.

Extraction/condensing turbines are commonly almost twice the cost of straight-through flow back pressure or condensing multi-stage turbines.[2] It can be more economical to use two turbines arranged in parallel, one with a back pressure design and one with a condensing design. However, extraction/condensing turbines offer more operating flexibility where the ratio of process steam to electricity is variable.

(e) Discussion

Steam turbines are durable with minimum routine maintenance and 3- to 5-year major overhaul schedules.[19] The diversion of steam flows from pressure relief valves by passing the steam through turbines offers the simplest, most economical method of cogeneration. In many cases the condensate and boiler feed pump flows would not be affected significantly.

The steam flow multiplier factors necessary to convert from pressure reducing valves and mechanical drives to electricity generation are listed in Table 7-8.[19] The tabulated values assume a single deaerator heater and could be reduced by as much as 4 percent by adding a low temperature water spray for desuperheating. The boiler plant steam output must increase proportionately in order to supply these increased steam flows.

The replacement of mechanical drives, and in some cases the addition of an indirect feedheater, are economical methods of increasing cogeneration.[19] For mechanical turbine conversions, approximately 35 to 45 percent of the gain in power output is used to supply the replacement electric motor drives. The cogeneration output can be increased further by the installa tion of a feedheater after the deaerator heater, but the boiler steam flow must be increased by an additional 5 to 10 percent, depending on the pressure.

TABLE 7-8

APPROXIMATE STEAM FLOW INCREASE FACTORS
STEAM INLET CONDITIONS

	Boiler Steam Flow Conditions psig/°F(kPa/°C)		
Extraction Pressure	600/750 (4240/400)	850/825 (5960/440)	1,250/900 (8720/480)
1. Pressure Reducing Value (PRV) Flows:			
to 50 psig (445 kPa)	1.20	1.24	1.27
to 150 psig (1135 kPa)	1.17	1.21	1.24
2. Mechanical Drive Flows:			
to 50 psig (445 kPa)	1.15	1.18	1.20
to 150 psig (1135 kPa)	1.11	1.14	1.16

Although the replacement of pressure reducing valves and mechanical drives will be generally economic, the report by Integ (1980)[19] specifically noted that for economic cogeneration the following conditions should be met:

1. Turbine generator steam flows should be in excess of 100,000 pph (45 360 kg/h) and provide a nominal power output of 5 MW or more.
2. Excess capability in boiler steam production should be about 15 percent of the total diverted steam flow to a pressure reducing value or mechanical drive turbine or up to 10 percent of existing boiler steam flow.
3. The demand for process steam should be stable, continuous and ideally correlate with the demand for electricity.

The development of the maximum potential for cogeneration from existing plants would require the following extensive modifications and additions.[19]

1. The addition of new turbine generators.
2. The replacement of boilers with units of higher pressure.
3. The elimination of pressure reducing valves (PRV) and the utilization of the high grade steam.
4. The replacement of low efficiency mechanical turbine drives with electric motors.
5. An increase in the number of feedwater heaters to the condensate feedwater system to increase steam pressures to the steam turbines.
6. The adoption of changes in the process to increase the turbine extraction pressures and decrease the loss in thermal energy at the bottom of the cycle.

Steam turbines are fitted with a number of control mechanisms to ensure dependable operation and achieve the maximum potential from cogeneration. The power generated by a steam turbine is dependent on the turbine shaft speed which is in turn dependent on the steam flow rate.[2] In back pressure turbines the steam flow is controlled at the turbine inlet by valves which regulate the steam to the turbine. The valves can be a series of spring-loaded nozzle valves which open in sequence as turbine load increases or a single throttle valve which regulates all of the steam load. Extraction and induction turbines further control steam flow by regulating the flow of intermediate pressure steam entering or leaving the turbine. Process steam demand is the controlling factor.

An overspeed trip is another controlling device and this device prevents damage to the turbine which could be caused by excessive speed.[2] The overspeed trip lever can close the inlet steam valve and stop the turbine.

Other instrumentation on the turbines include the following: low bearing-oil-pressure trip, shaft vibration meter and steam condition (pressure and temperature) meters.

7.7 EFFECT OF MOISTURE CONTENT ON WOOD FUEL BURNING

The steam capability of hog fuel-fired boilers is variable because of the variable moisture content and to a lesser extent the species mix of the fuel.[19] However, pre-drying is generally not justified because of the added cost.

The increased moisture content of undried wood waste reduces the combustion rate in a boiler for three reasons:[44,64]

1. More energy is consumed in the furnace to evaporate the water from the fuel.

2. More excess air is required to help dry the fuel.

3. For wood waste fuels containing more than 20 to 30 percent moisture, the rate of combustion at a given temperature decreases markedly with increasing moisture content.

These characteristics are illustrated in Figure 7-15. Less water and less excess air combine to produce higher temperatures in the furnace which increases the combustion rate. At moisture contents above 20 to 30 percent, the moisture content becomes the most important factor in controlling the rate of combustion. Therefore, steam production from a furnace can be increased by decreasing the moisture content of the fuel. The effect of moisture content on the rate of steam production for grate firing is illustrated in Figure 7-16.[65] The rate of steam production decreases markedly with increasing moisture content. The effect of particle size on the rate of steam production is also evident because of the difference between pulverized and grate firing. The combustion rate is higher for pulverized firing and the increased combustion rate produces higher temperatures.

For pulverized firing at a nominal particle size of 0.5 mm and a moisture content of 30 percent, the particle in the furnace is completely burned in about one second.[64] Residence times are 1 to 2 seconds. Therefore, wood particles of this size are suitable for pulverized firing. However, fines must be reduced to ensure adequate residence time for larger particles.

As previously noted, wood burns faster and with a hotter flame if it is drier and these improved burning characteristics produce the following benefits:[64]

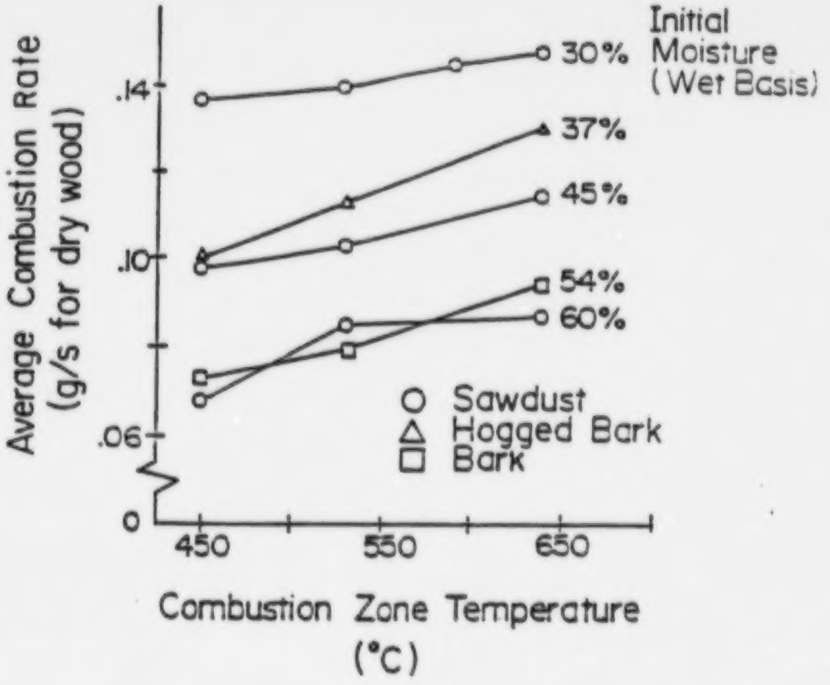


Figure 7-15

THE RELATIONSHIP OF COMBUSTION RATE TO COMBUSTION TEMPERATURE FOR SOME BATCH BURNING EXPERIMENTS

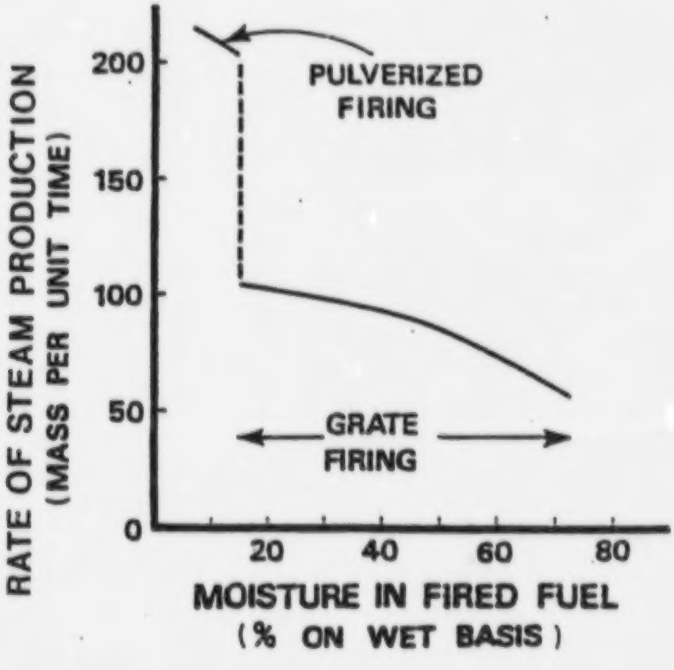


Figure 7 - 16

EXAMPLE OF THE EFFECT OF FUEL MOISTURE CONTENT ON RATE OF STEAM PRODUCTION

1. Thermal efficiency is increased for several reasons. The volume of flue gas is reduced with the decrease in excess air. Unburned material in the fly ash is reduced with the faster combustion rates. Thermal efficiency is increased typically from 62 to 70 percent with the addition of a flue gas dryer. With shell-and-tube dryers low pressure steam can be recovered to produce wood-fired boiler efficiencies of 82 percent.

2. Unburned particulate emissions from grate firing can be reduced by drying. These reductions are produced by increasing the completeness of combustion and the residence time. The longer residence time is caused, in turn, by lower gas velocities, reduced excess air and reduced evaporation of water in the furnace.

3. More stable boiler operation is feasible because wood burns more quickly when it is drier.

4. Some chlorinated organics which are carcinogens and mutagens are emitted from wood-fired units and these emissions decrease as the combustion temperature increases.

5. Less auxiliary fuel is required.

There is one disadvantage resulting from a decrease in the moisture content of wood fuels. Below 30 to 35 percent air borne dust from conveyor systems can increase significantly.

SECTION 8.0 - THEORY OF COGENERATION

8.1 INTRODUCTION

This chapter describes the methods of cogeneration, the variations within each and the effects of these variations on efficiency. The relationship of the various components of the cogeneration plant are also described.

In determining the potential for cogeneration at an individual plant four types of data are required:

1. Total energy use by category including electricity and fossil fuels.
2. Steam data.
3. Direct heat data.
4. Mechanical work data.

The data should be collected with sufficient frequency to indicate short to medium term variation in energy use. The requirement for mechanical work data could be eliminated because electric motors are usually more economical and should replace most mechanically driven machines.

As noted in Chapter 6.0, cogenerating plants can use many fuels. However, hog fuel, natural gas and residual oil are the principal fuels in the B.C. pulp and paper industry and there is considerable interest in increasing the use of hog fuel. These fuels are commonly used to produce steam in a boiler and the steam passes through turbines and processes to produce the desired amount and type of thermodynamic work. Alternately, the steam can be used to drive a steam engine.

Gas turbine/combined cycle plants can use natural gas, wood gas or oil for cogeneration. Exhaust from the gas turbine passes through the steam generator. The steam generator may use supplementary firing to increase the energy to the steam turbine before exhausting to the process.

8.2 STEAM RATE

The steam rate is the quantity of steam required to produce a unit of electricity (kW·h) and is a measure of turbine performance. The theoretical steam rate (TSR) in kg/kW·h under isentropic expansion is estimated by the following equation:[2]

$$TSR = \frac{TC}{h_1-h_2}$$

where: TC is the ideal isentropic thermal to electrical conversion constant (3600 kJ/kW·h)

h_1 is the steam enthalpy at inlet conditions (kJ/kg).

h_2 is the steam enthalpy at outlet conditions after isentropic expansion (kJ/kg).

The theoretical steam rate is dependent only on inlet pressure, inlet temperature and outlet pressure and is the same for all turbines under the same conditions.

The actual steam rate (ASR) in kg/kW·h is estimated by the following equation:[2]

$$ASR = \frac{TC}{h_1-h_{2a}}$$

where: h_{2a} is the steam enthalpy at actual outlet conditions (kJ/kg).

The actual steam rate is determined by steam conditions and turbine design. Some turbine design parameters and their effects on the steam rate are listed in Table 8-1.[2]

Overall turbine efficiency (Eff) is estimated by the following equation:

$$Eff = \frac{TSR}{ASR}$$

assuming the same design and operating conditions. Typical steam rates and turbine efficiencies for small turbines are listed in Table 8-2.[2]

Turbine heat rate (HR) in kJ/kW·h is another useful measure of turbine performance. The heat rate is the amount of thermal energy required by the turbine for each unit of energy output while neglecting gear and generator losses. The heat rate is estimated by the following equation:[2]

$$HR = ASR\ (h_1 - h_{2a}')$$

where: h_{2a}' is the steam enthalpy at actual outlet conditions (allowing for heat losses) if steam is used by the process or the saturated water enthalpy at outlet pressure if steam is condensed or exhausted from the system (kJ/kg).

If the steam used for the process and gear and generator losses are neglected h_{2a}' equals h_{2a}. The actual or plant heat rate (AHR) can

TABLE 8-1

EFFECTS OF CHANGES IN OPERATING CONDITIONS ON STEAM RATE

Parameter Increased	Effect on Steam Rate
Inlet Pressure	Decrease
Inlet Temperature	Decrease
Outlet Pressure	Increase
Outlet Temperature	Increase
Shaft Speed	Decrease*[1]
Number of Stages	Decrease
Leakage	Increase

---

*[1] Some turbines at certain conditions will actually have an increased steam rate at a higher shaft speed, but generally as shaft speed increases steam rate decreases.

TABLE 8-2

TYPICAL STEAM RATES AND TURBINE EFFICIENCY FOR TURBINES WITH A RATED OUTPUT OF LESS THAN 5 MW*[1]

Turbine Design	Actual Steam Rate (kg/kW·h)	Turbine Efficiencies (%)
Back-Pressure Single-Stage	18.0 - 30.0	45 - 65
Back-pressure Multiple-Stage	6.0 - 22.0	55 - 75
Condensing Multiple-Stage	2.5 - 7.0	65 - 80

---

*[1] The steam conditions are 600 psig/750°F (4240 kPa/400°C).

be determined by dividing HR by the mechanical efficiency. The actual heat rate is usually used to describe the performance of a condensing turbine, whereas a back pressure turbine is usually described by using the actual steam rate and turbine efficiency. Heat rates are dependent on the same system features as steam rates. The actual heat rate can be expressed in terms of thermal efficiency (TE) by the following equation:[2]

$$TE = \frac{100 \cdot TC}{AHR}$$

Thermal efficiency makes allowance for all heat and mechanical losses.

The performance characteristics of extraction and induction turbines are compared by their efficiencies and are commonly illustrated by a graph of throttle steam flow versus power output at various extraction or induction flows. Figure 8-1 is an example of this type of graph for a 5000 kW generator with inlet steam conditions of 4000 kPa/400°C, extraction at 1600 kPa and exhaust at 50 mm Hg[2]. Steam rates can be determined by dividing the throttle steam flow by the power output for the appropriate operating conditions.

The approximate exhaust steam flow versus power output for straight-through back pressure turbines between 100 kW and 5 MW is illustrated in Figure 8-2.[2,66] The assumptions of steam conditions are noted on the figure. A condensing/extraction turbine in a topping cycle could be more economical if the steam to electrical requirements are less than those produced by back pressure turbines.

8.3 COGENERATION SYSTEMS

The optimization of steam inlet pressure and temperature is important in designing a back pressure cogeneration power plant.[19] At a given back pressure, the higher the inlet pressure the larger the potential output. However, turbine efficiency deteriorates with increasing inlet pressure because of increased blade and inter-stage leakage and reduced blade sizes at the early stages of expansion. In addition, losses are proportionately larger on smaller turbine units.

In designing the system, the inlet steam temperature is selected to give a superheat of approximately 11°C at the turbine exhaust.[19] This superheat prevents condensation in the pipework between the turbine and the process. For a given inlet steam condition and exhaust pressure, the condition of the steam at the exhaust is determined by the thermodynamic turbine efficiency where the condition of the steam refers to the degree of superheat or the dryness fraction. The higher the efficiency, the higher the inlet temperature that can be used and the larger the power output for a given heat flow to the process. Higher turbine efficiency causes steam to be exhausted at lower enthalpy and steam flow must

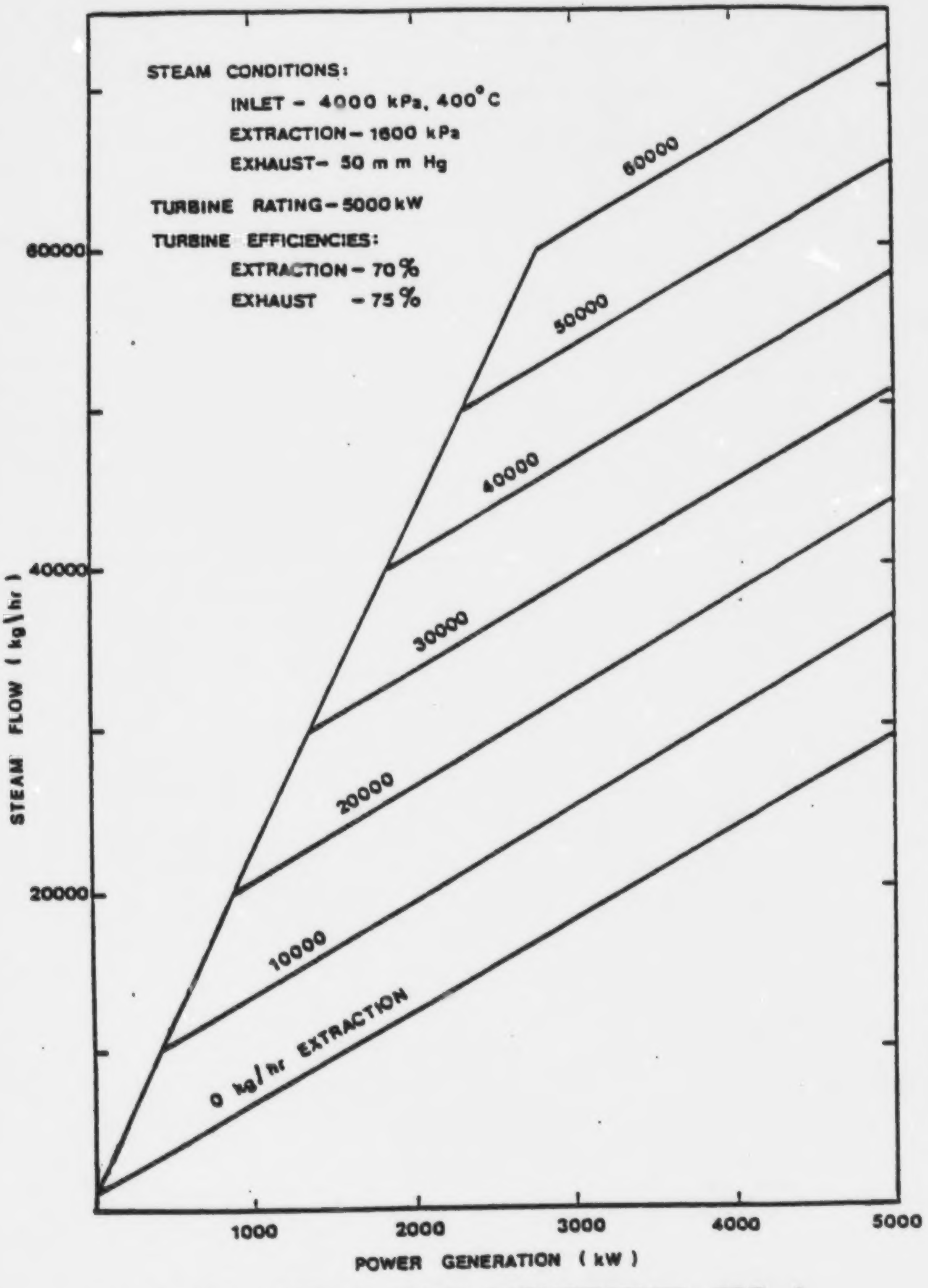


Figure 8-1 **STEAM FLOW REQUIREMENTS FOR A CONDENSING/EXTRACTION TURBINE**

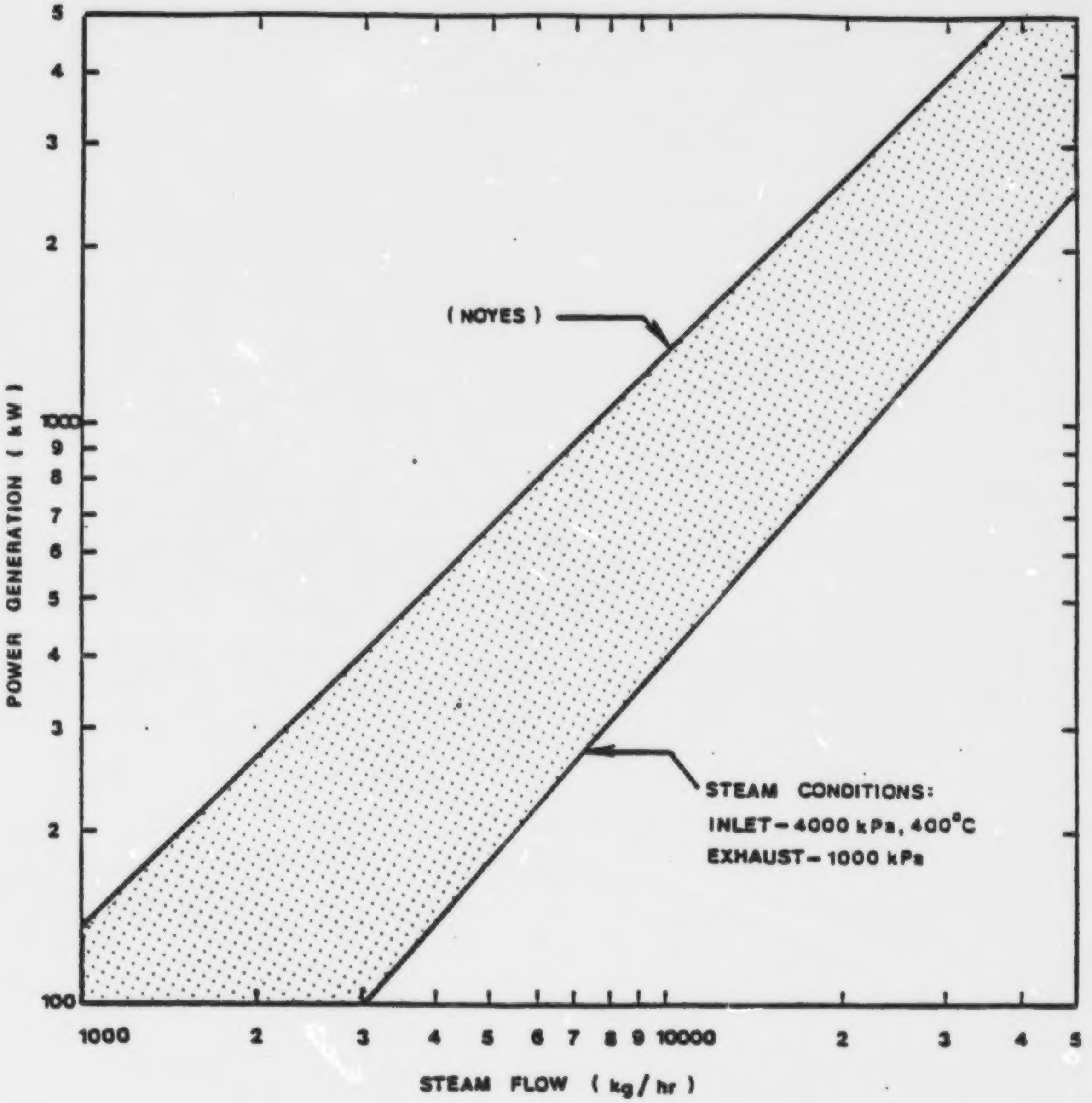


Figure 8-2 STEAM FLOW REQUIREMENTS FOR BACK PRESSURE TURBINES

increase to give an equivalent heat flow to process. Therefore, both process steam and electricity are increased assuming the same inlet pressure, inlet temperature and back pressure. As noted previously, heat rate is the ratio of the thermal energy supplied (in kJ) per unit of energy output (in kW·h). When applied to a condensing turbine cycle it provides a measure of the thermal/electrical energy conversion efficiency of the turbine cycle. When applied to a back pressure turbine used in cogeneration, the heat from the turbine is rejected to the process which reduces the heat absorption and loss attributable to electricity generation. Energy losses include boiler, generator, auxiliaries, process condensate, cooling water and blowdown losses.

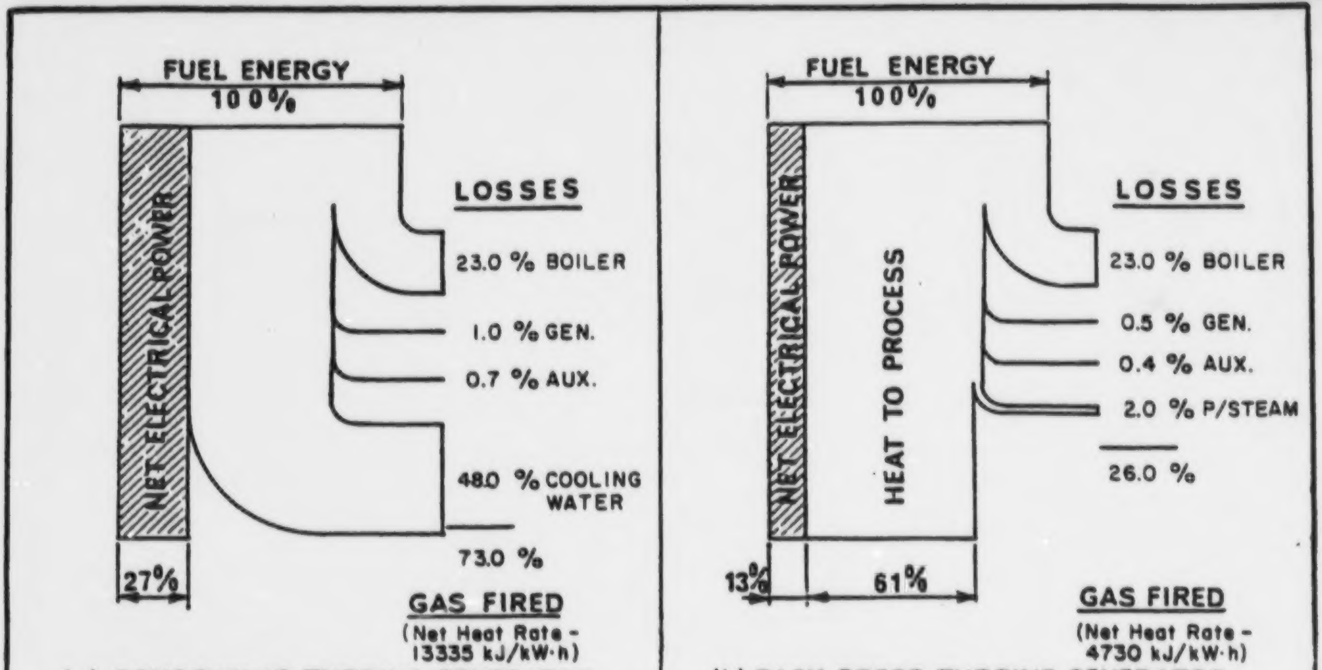
Boiler losses significantly reduce overall thermal efficiency. Most of the losses are through the stack and they are affected by the type of fuel, the products of combustion, the moisture content, the size of the unit and the amount of excess air required for combustion. The sources of thermal energy losses for a small industrial generating/cogenerating plant are illustrated in Figure 8-3.[19] The gas-fired condensing turbine generator has an overall thermal efficiency of 27 percent (Figure 8-3(a)); most of the thermal losses are caused by condensing the steam to permit recirculation through the boiler. The cycle is illustrated in Figure 8-4. The impact of fuel type on thermal efficiency for a cogenerating plant with a back pressure turbine generator and fired on natural gas, oil and hog fuel are illustrated in Figs. 8-3(a) through 8-3(d) and 8-5 through 8-7. Oil-fired generation has the highest thermal efficiency at 78 percent and hog fuel-fired cogeneration has the lowest thermal efficiency at 60.4 percent. The ratio of net electrical power to process heat is related to the type of prime mover, the type of turbine and the back pressure.

The electrical to thermal energy ratio is typically 0.25 for fossil fuel-fired steam turbine cogenerating units and the comparable figures for gas turbine and diesel engine cogenerating units are 0.6 and 1.4 respectively.[2] These ratios can change significantly depending on the demand for electricity and thermal energy. Combustion turbine and combined cycle cogeneration plants using natural or synthetic gas can produce a high percentage of their energy output in the form of electricity.[1]

The electrical/thermal ratio for condensing and back pressure turbines under a range of turbine inlet conditions are illustrated in Figure 8-8.[2] The range for condensing turbines, back pressure turbines at 345 kPag and for back pressure turbines at 1000 kPag are 0.25 to 0.43, 0.05 to 0.18 and 0.03 to 0.12 respectively.

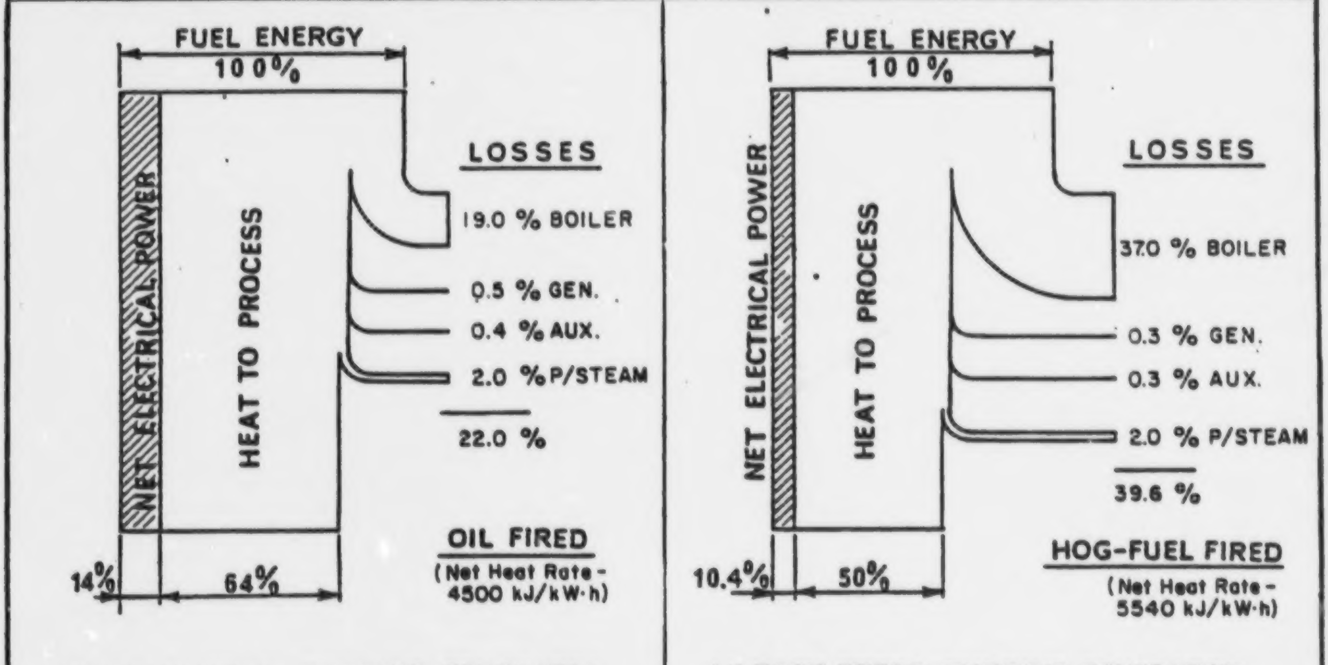
8.4 MOLLIER CHART - STEAM RATES

As illustrated in the Mollier Chart (Figure 8-9) the power output increases with increasing turbine steam inlet conditions for a given back pressure which is set by the process.[19] The expansion lines for 150 psig (1135 kPa) and 50 psig (445 kPa) are indicated in Figure 8-9. The expansion lines assume a turbine efficiency of


FUEL ENERGY
100%
NET ELECTRICAL POWER
LOSSES
23.0 % BOILER
1.0 % GEN.
0.7 % AUX.
48.0 % COOLING WATER
73.0 %
27%
GAS FIRED
(Net Heat Rate - 13335 kJ/kW·h)
FUEL ENERGY
100%
NET ELECTRICAL POWER
HEAT TO PROCESS
LOSSES
23.0 % BOILER
0.5 % GEN.
0.4 % AUX.
2.0 % P/STEAM
26.0 %
13%
61%
GAS FIRED
(Net Heat Rate - 4730 kJ/kW·h)

(a) CONDENSING TURBINE GENERATOR

(b) BACK PRESS. TURBINE GENERATOR


FUEL ENERGY
100%
NET ELECTRICAL POWER
HEAT TO PROCESS
LOSSES
19.0 % BOILER
0.5 % GEN.
0.4 % AUX.
2.0 % P/STEAM
22.0 %
14%
64%
OIL FIRED
(Net Heat Rate - 4500 kJ/kW·h)
FUEL ENERGY
100%
NET ELECTRICAL POWER
HEAT TO PROCESS
LOSSES
37.0 % BOILER
0.3 % GEN.
0.3 % AUX.
2.0 % P/STEAM
39.6 %
10.4%
50%
HOG-FUEL FIRED
(Net Heat Rate - 5540 kJ/kW·h)

(c) BACK PRESS. TURBINE GENERATOR

(d) BACK PRESS. TURBINE GENERATOR

Figure 8-3 TYPICAL THERMAL ENERGY UTILIZATION DIAGRAMS

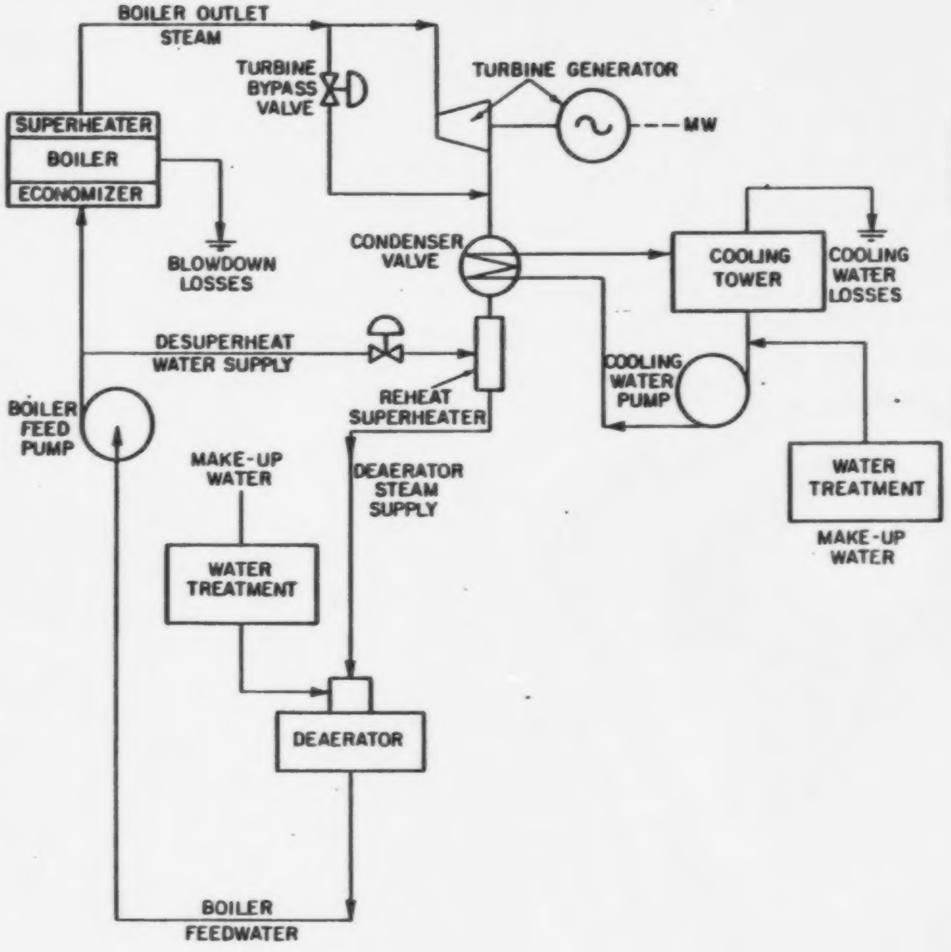

BOILER OUTLET STEAM
TURBINE BYPASS VALVE
TURBINE GENERATOR
MW
SUPERHEATER
BOILER
ECONOMIZER
BLOWDOWN LOSSES
CONDENSER VALVE
COOLING TOWER
COOLING WATER LOSSES
DESUPERHEAT WATER SUPPLY
COOLING WATER PUMP
BOILER FEED PUMP
REHEAT SUPERHEATER
MAKE-UP WATER
DEAERATOR STEAM SUPPLY
WATER TREATMENT
MAKE-UP WATER
WATER TREATMENT
DEAERATOR
BOILER FEEDWATER

Figure 8-4

SCHEMATIC OF CONDENSER TURBINE GENERATOR

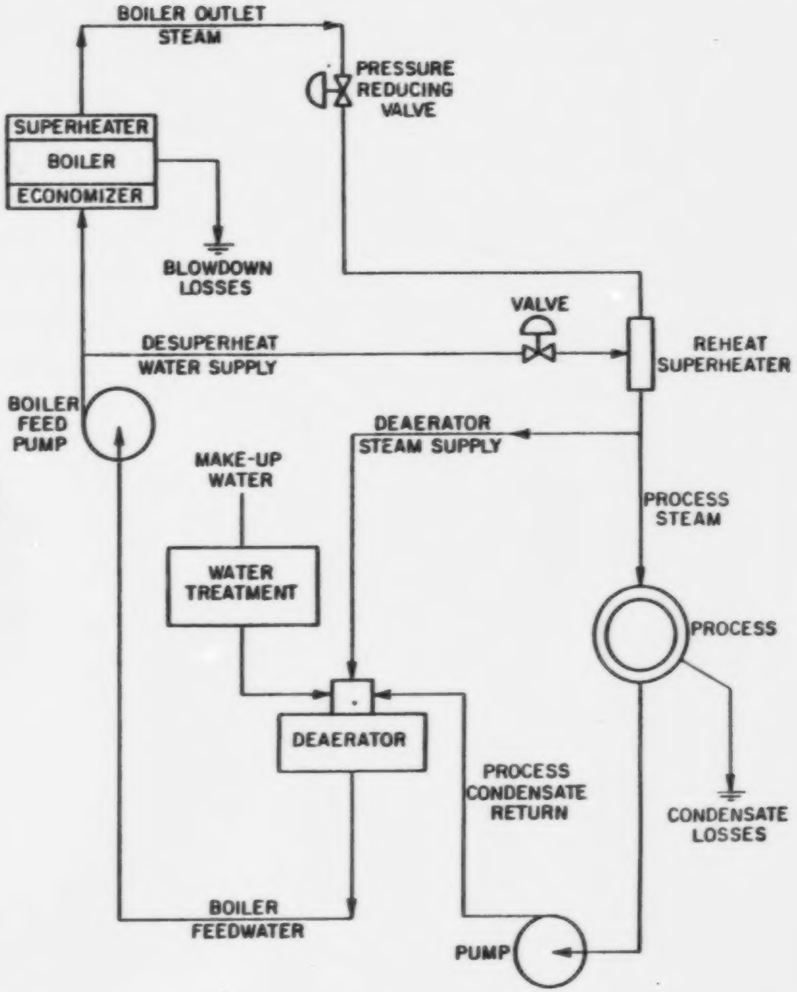

BOILER OUTLET STEAM
PRESSURE REDUCING VALVE
SUPERHEATER
BOILER
ECONOMIZER
BLOWDOWN LOSSES
VALVE
DESUPERHEAT WATER SUPPLY
REHEAT SUPERHEATER
BOILER FEED PUMP
DEAERATOR STEAM SUPPLY
MAKE-UP WATER
PROCESS STEAM
WATER TREATMENT
PROCESS
DEAERATOR
PROCESS CONDENSATE RETURN
CONDENSATE LOSSES
BOILER FEEDWATER
PUMP

Figure 8-5

SCHEMATIC OF PROCESS STEAM GENERATION

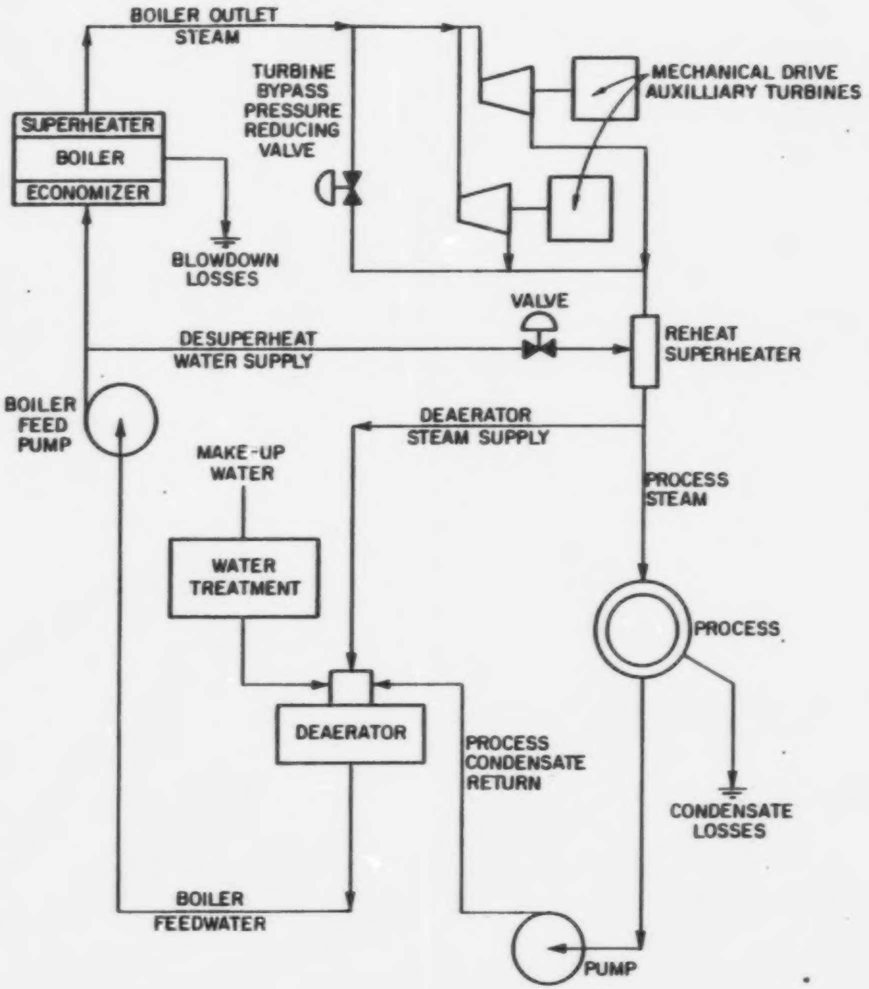

BOILER OUTLET STEAM
TURBINE BYPASS PRESSURE REDUCING VALVE
MECHANICAL DRIVE AUXILLIARY TURBINES
SUPERHEATER
BOILER
ECONOMIZER
BLOWDOWN LOSSES
VALVE
DESUPERHEAT WATER SUPPLY
REHEAT SUPERHEATER
BOILER FEED PUMP
DEAERATOR STEAM SUPPLY
MAKE-UP WATER
PROCESS STEAM
WATER TREATMENT
PROCESS
DEAERATOR
PROCESS CONDENSATE RETURN
CONDENSATE LOSSES
BOILER FEEDWATER
PUMP

Figure 8-6

SCHEMATIC OF COGENERATION WITH MECHANICAL DRIVE TURBINES

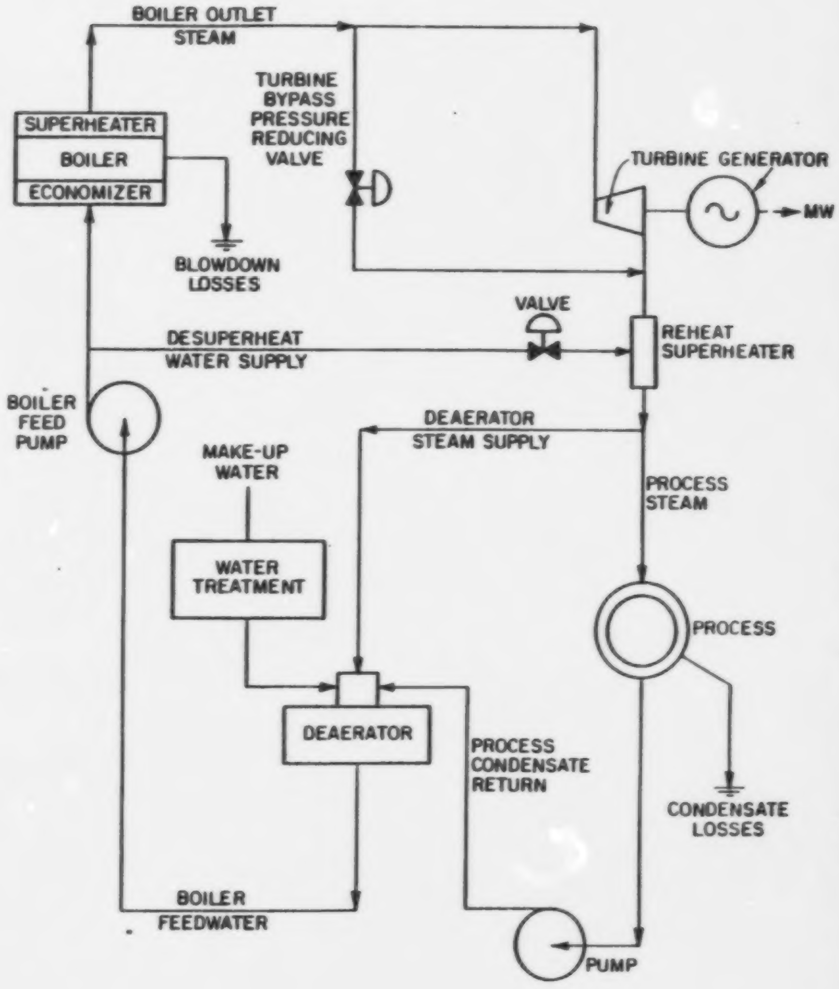

BOILER OUTLET STEAM
TURBINE BYPASS PRESSURE REDUCING VALVE
SUPERHEATER
BOILER
ECONOMIZER
TURBINE GENERATOR
MW
BLOWDOWN LOSSES
VALVE
DESUPERHEAT WATER SUPPLY
REHEAT SUPERHEATER
BOILER FEED PUMP
DEAERATOR STEAM SUPPLY
MAKE-UP WATER
PROCESS STEAM
WATER TREATMENT
PROCESS
DEAERATOR
PROCESS CONDENSATE RETURN
CONDENSATE LOSSES
BOILER FEEDWATER
PUMP

Figure 8-7

SCHEMATIC OF COGENERATION WITH ELECTRICAL GENERATION

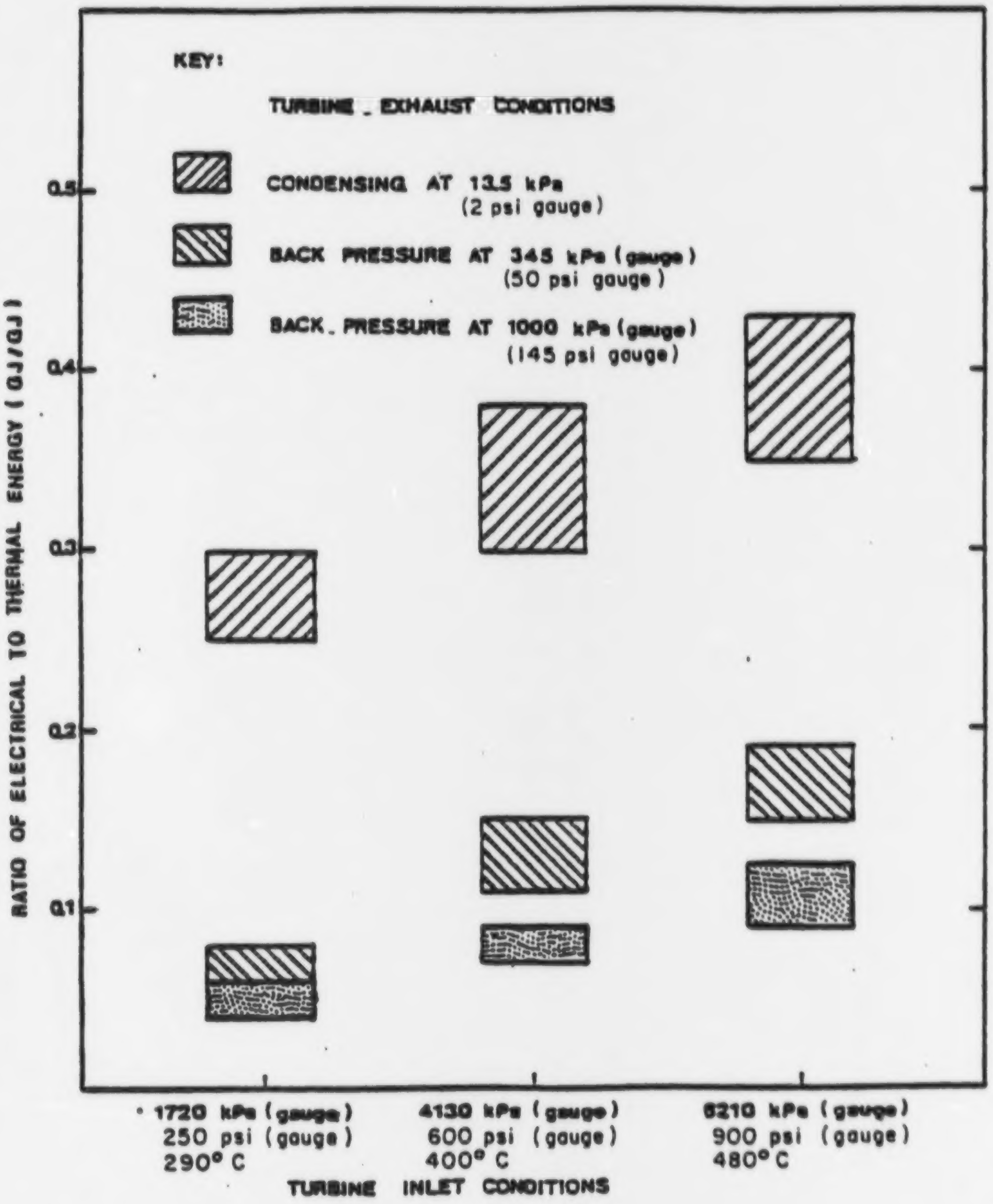


Figure 8-8 RATIO OF ELECTRICAL TO THERMAL ENERGY FOR STEAM TURBINES

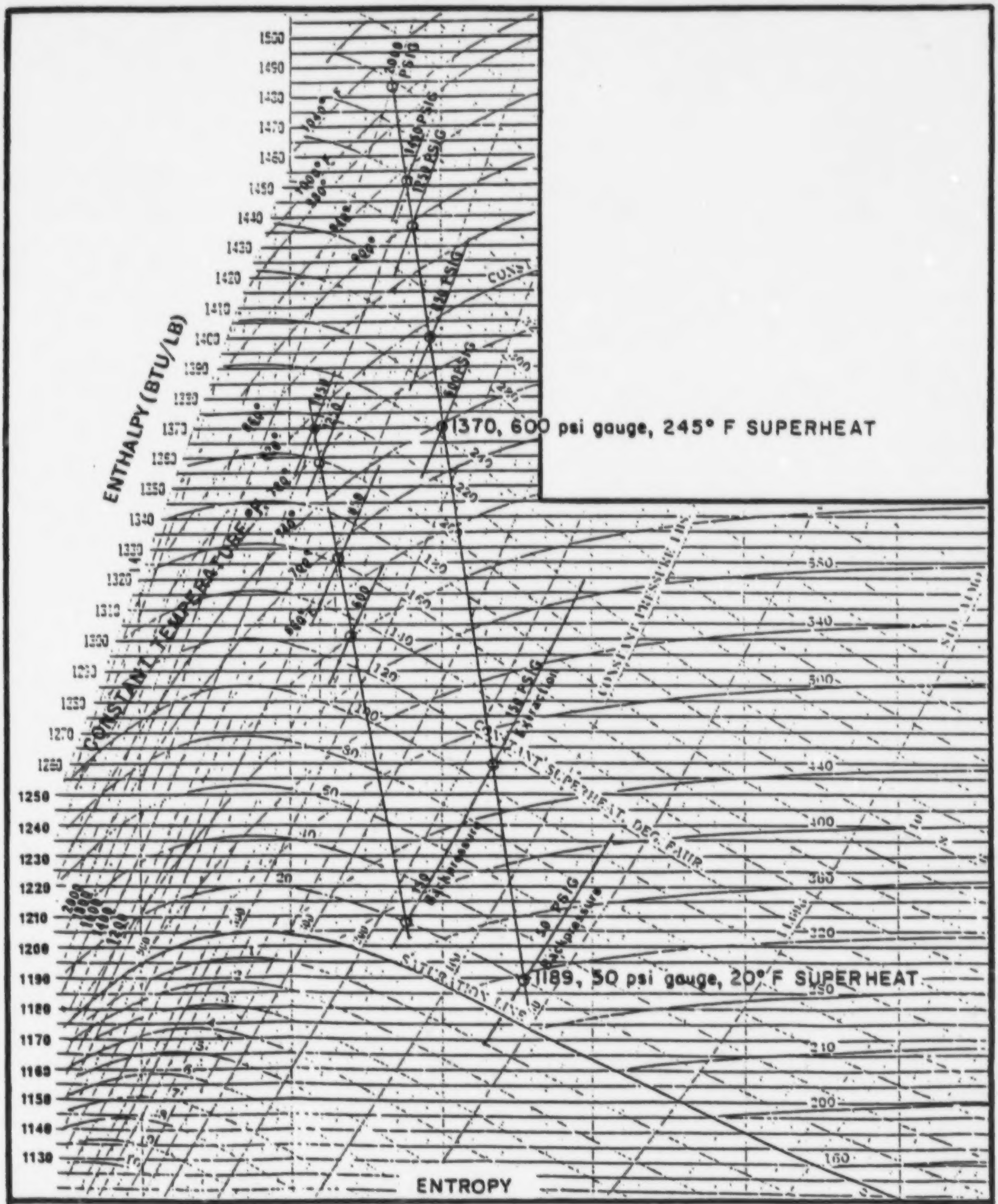


Figure 8 - 9

Mollier Chart - TYPICAL TURBINE EXPANSION LINE FOR PROCESS BACKPRESSURES OF 50&150 PSIG & EXTRACTION PRESSURE OF 150 PSIG

80 percent at steam flow rates of 400,000 pph (182 000 kg/h). The efficiency is lower at lower flows and/or pressures. In general, the inlet temperature is adjusted downward to maintain constant back pressure superheat, maximum turbine steam flow and maximum power output for a given steam inlet pressure.

The steam rate is the turbine steam flow rate per net kilowatt hour of electrical energy produced (in lb/kW·h). The Mollier Chart can be used to estimate the overall turbine plant steam rate for a given steam inlet pressure and back pressure. For example, at a steam inlet pressure 600 psig (4240 kPa) at 750°F (approx. 400°C) and a back pressure of 50 psig (445 kPa) at 20°F (3.6°C) of superheat the enthalpy drop is 1370 Btu/lb to 1189 Btu/lb (i.e. 3187 kJ/kg to 2766 kJ/kg) or 181 Btu/lb (421 kJ/kg). Converting one form of energy unit to another (Btu/lb or kJ/kg to kW·h/lb or kW·h/kg) yields a basic steam rate of 18.85 lb/kW·h (8.55 kg/kW·h). However, steam leakage, mechanical losses, electrical losses, plant auxiliaries and other corrections reduce efficiency to 16 percent. Therefore, the overall turbine plant steam rate would be approximately 22 lb/kW·h (10 kg/kW·h).

Typical steam rates for 150 psig (1135 kPa) extraction conditions and 50 psig (445 kPa) back pressure conditions for various steam inlet conditions are listed in Table 8-3. These steam inlet conditions range from 600 psig (4240 kPa) to 1500 psig (10 445 kPa). For higher steam inlet conditions, the overall steam rates decrease or alternatively the power output increases (Figure 8-10).

In a cogenerating plant with condensing capacity, steam is supplied to the process from the turbine extraction points while the remaining steam is expanded under condenser vacuum conditions. The greater the expansion, the lower the steam rate that is required for a constant power output and the lower the heat rate.

8.5 STEAM PRESSURES AND PROCESS STEAM DEMAND

Process heat requirements differ from industry to industry and with the technology within an industry. Most non-forest product industry process heat users produce steam at low pressures. In a few cases, they produce medium pressure (400 to 600 psig; 2860 to 4240 kPa) steam to generate some electricity and mechanical energy.[19]

Pressure requirements for process steam in the forest industry are typically less than 200 psig (1480 kPa). Where steam output flow requirements exceed 150,000 pph (330 000 kg/h) the boiler should generate steam at 450 to 600 psig (3200 to 4240 kPa)or higher.[19]

From Figs. 8-5 to 8-7 the process steam demand is the weighted sum of the boiler steam output, the desuperheat water supply and deaerator steam supply. The desuperheat water supply can be taken before or after the deaerator. On conversion to cogeneration, the process steam pressure and temperature set the exhaust condition for the turbine. The turbine efficiency should be compatible with

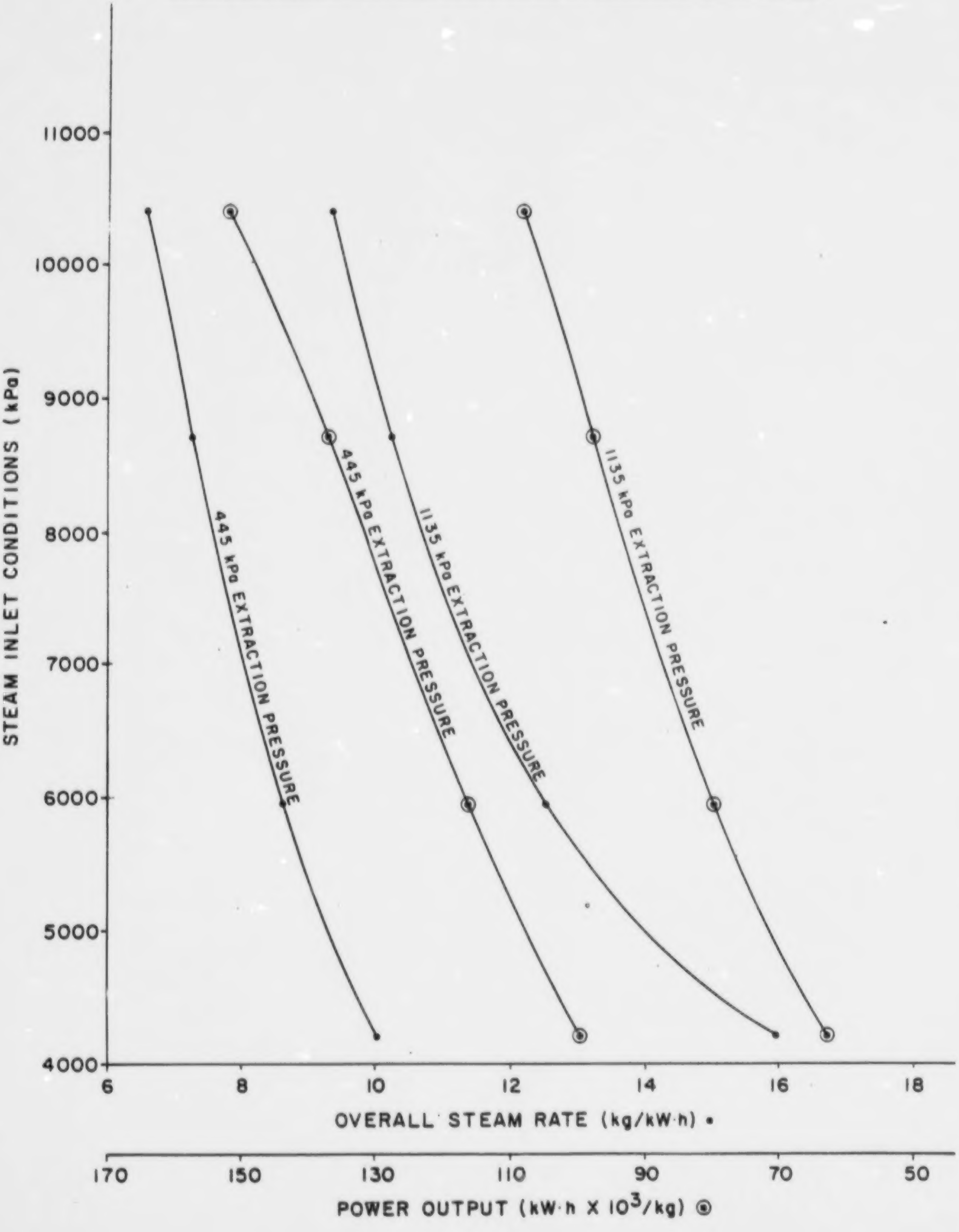
TABLE 8-3

OVERALL STEAM RATES (lb/kW·h-kg/kW·h)

	Steam Inlet Conditions							
	(psig/°F)				(kPa/°C)			
Extraction Pressure	600/750	850/825	1250/900	1500/900	4240/400	5960/440	8720/480	10445/480
50 psig	22	19	16	14.5				
445 kPa					10.0	8.6	7.3	6.6
150 psig	35	27.5	22.5	20.5				
1135 kPa					15.9	12.5	10.2	9.3

Figure 8-10

OVERALL STEAM RATE AND POWER OUTPUT



boiler steam conditions, so essentially no desuperheating of the turbine exhaust is required.

Some typical values of process conditions in the forest industry are listed in Table 8-4. Condensate losses can be as high as 40 percent. The boiler outlet steam flow must increase by 20 percent to optimize the electrical generation and maintain the process steam flow.

Mechanical drive turbines in lieu of electrical turbine generators can be effective where equipment with variable and high speed is required.[19] However, thermal efficiencies are low with average steam rates of 50 to 60 lb/kW·h (22.7 to 27.3 kg/kW·h). For example, the replacement of a 6000 hp (58 860 kW) boiler with an average steam rate of 55 lb/kW·h (25 kg/kW·h) would release 246,000 lb/h (542 340 kg/h) of steam which if expanded through a back pressure turbine with an average steam rate of 27 lb/kW·h (12.3 kg/kW·h) produces an apparent power gain of 4550 kW. The low efficiency of mechanical drive turbines requires desuperheat water additions of as much as 15 percent of turbine steam flows. The increased turbine steam flows would increase generated power output to approximately 10 500 kW. Therefore, the net power gain would be 5850 kW.

Steam as sent to process is usually saturated, but it can be superheated. Superheated process steam is usually between 2170 and 2860 kPa and the amount of superheat is usually less than 38°C.[42]

8.6 FEED HEATERS

Feed heaters in cogeneration plants increase power output.[19] The power increase is caused by the increased boiler steam flow which is necessary to supply the heaters. This allows expansion in the turbine to feed heater extraction conditions and increases power output without adding to process heat supply. These conditions are described further and illustrated in Section 12.5.

The fuel input must increase to balance the increased power output. Increases in power output from adding feed heaters diminish rapidly and the maximum combination is normally one deaerator direct contact heater and two indirect heaters. Process steam plants usually have only one deaerator. In a cogeneration plant the deaerator is commonly supplied with steam at 50 psig (445 kPa) and uses 10 to 13 percent of the total boiler steam flow. For a steam pressure of 600 psig (4,240 kPa) the addition of one deaerator before the feed heater increases power output by 5 to 6 percent and the addition of a second feed heater increases power output by a further 4 to 5 percent. The increases in power output are higher at higher pressures. The increases in power output require boiler steam flows to increase 7 to 9 percent for the first heater addition and 17 to 19 percent for two heaters; these estimates are dependent on boiler pressures and heat extraction conditions. With two stages of feed heating, the feed water enthalpy at the inlet to the boiler is increased by 300 to 370 kJ/kg. However, conversion

TABLE 8-4

TYPICAL VALUES FOR PROCESS CONDITIONS IN THE FOREST INDUSTRY

Process Condensate Loss (%)	30
Process Pressure (kPa)	445
Deaerator Pressure (kPa)	445
Enthalpy of Desuperheat Water (kJ/kg)	580
Boiler Conditions (kPa/°C)	4240/400

of an existing plant to cogeneration with the addition of feed heaters could require significant modifications to the feed water systems including the replacement of boiler feed pumps.

8.7 EFFICIENCY OF COGENERATION

The actual efficiency of cogeneration depends on the type of fuel, type of combustion technology, balance between thermal and electrical loads, mode of operation and the ability of the operating personnel.

As previously noted, hog fuel is common in cogenerating plants in B.C.. The as-fired heating value of hog fuel Q(in kJ/kg of wet hog fuel) can be estimated as follows:[28]

$$Q = (E-W-T-S)(1-A)$$

where: E is the bone dry heating value of hog fuel (kJ/kg).

W is the heat loss because of the heating of water formed from the combustion of hydrogen in the hog fuel (kJ/kg of dry hog fuel).*[1]

T is the heat loss caused by heating the moisture in the hog fuel (kJ/kg of dry hog fuel).*[2]

S is the heat loss as a result of heating mineral matter in the hog fuel (kJ/kg on a dry basis).*[3]

A is the moisture content (on a wet basis) of hog fuel (%).

*[1] W = 0.54 kg of water (formed from hydrogen)/kg of hog fuel x 2442 kJ/kg which is the heat of vaporization of water = 1318.7 kJ/kg.

*[2] T = B x 2,442 kJ/kg.

where: B is the moisture content in kilograms (on a dry basis) per kilogram of hog fuel i.e. includes surface moisture (dimensionless).

*[3] S = $0.84 \times D \times (\tau_1 - \tau_2)$

where: 0.84 is the specific heat of sand (kJ/kg deg C)

D is the kg of ash/kg of dry hog fuel (0.0638 in tests by Nelson (1983)).[32]

τ_1 is the temperature at which the ash leaves the boiler (degrees C) = 204°C.

τ_2 is ambient temperature (degrees C) = 15.6°C.

Cogeneration is more efficient than conventional electricity generation because heat and electric power are both utilized. System efficiency (EFF) in percent can be defined as follows:[67]

$$EFF = \left(\frac{H_{EO} + H_{TO}}{FI}\right) 100$$

where: H_{EO} is the electric energy output (kJ).

H_{TO} is the heat energy output (kJ).

F_I is the fuel energy input (kJ).

Another measure of efficiency is the net heat rate (HR_n) in kJ/kW·h which can be estimated as follows:[67]

$$HR_n = \frac{F_I - \frac{T^E}{B^{EFF}}}{E_{EO}}$$

where: T^E is the thermal energy to process (kJ).

B_{EFF} is the process boiler efficiency (%).

E_{EO} is the electric energy output (kW·h).

This net heat rate for a cogenerating facility is essentially the heat rate for a conventional plant minus a correction factor for the supply of process heat. A third measure of the efficiency of cogeneration systems is the heat rate improvement (r_{fs}) in kJ/kW·h which can be estimated as follows:[67]

$$r_{fs} = \frac{H_{TO}}{(HR_t - HR_n)\, E_{EO}}$$

where: HR_t is the utility heat rate for conventional thermal power generation (kJ/kW·h).

$\frac{H_{TO}}{E_{EO}}$ is the steam to electricity ratio $\left(\frac{kJ}{kW \cdot h}\right)$.

SECTION 9.0 - COGENERATION AND THE FOREST INDUSTRY IN BRITISH COLUMBIA

9.1 INTRODUCTION

The forest industry in B.C. consists of four sectors: lumber (sawmills), plywood and particle board, pulp and paper. Sawmills, plywood plants and particle board plants tend to have low load factors which severely limits the potential for cogeneration in these segments of the forest industry. Sawmills require electricity for lighting and motors and heat for kiln drying, water heating and space heating. Sawmills in B.C. use a variety of fuels to meet their energy needs. However, most cogeneration in B.C. is in the pulp and paper sectors.

Pulp and paper production can be non-integrated or integrated. In a non-integrated operation the production of market pulp from logs or the manufacture of paper products from purchased pulp are totally independent. In an integrated operation raw timber is processed into paper products at one mill. There are many stages in pulp and paper processing as illustrated in the flow diagram (Figure 9-1).[22,68] Debarking, chipping and grinding or pulverizing are described in Chapters 6.0 and 7.0. The other stages are described in this section including pulping, washing, screening, thickening, bleaching (optional) and refining to produce pulp and stock preparation, forming, pressing, drying and finishing to produce paper. Pulp mills require electricity for lighting and for motors used in grinding, stirring, rolling, etc. They require process steam for product heating, evaporation, mechanical drives, space heating, etc.[19]

9.2 SAWMILLS - LUMBER AND PLYWOOD PRODUCTION

(a) Introduction

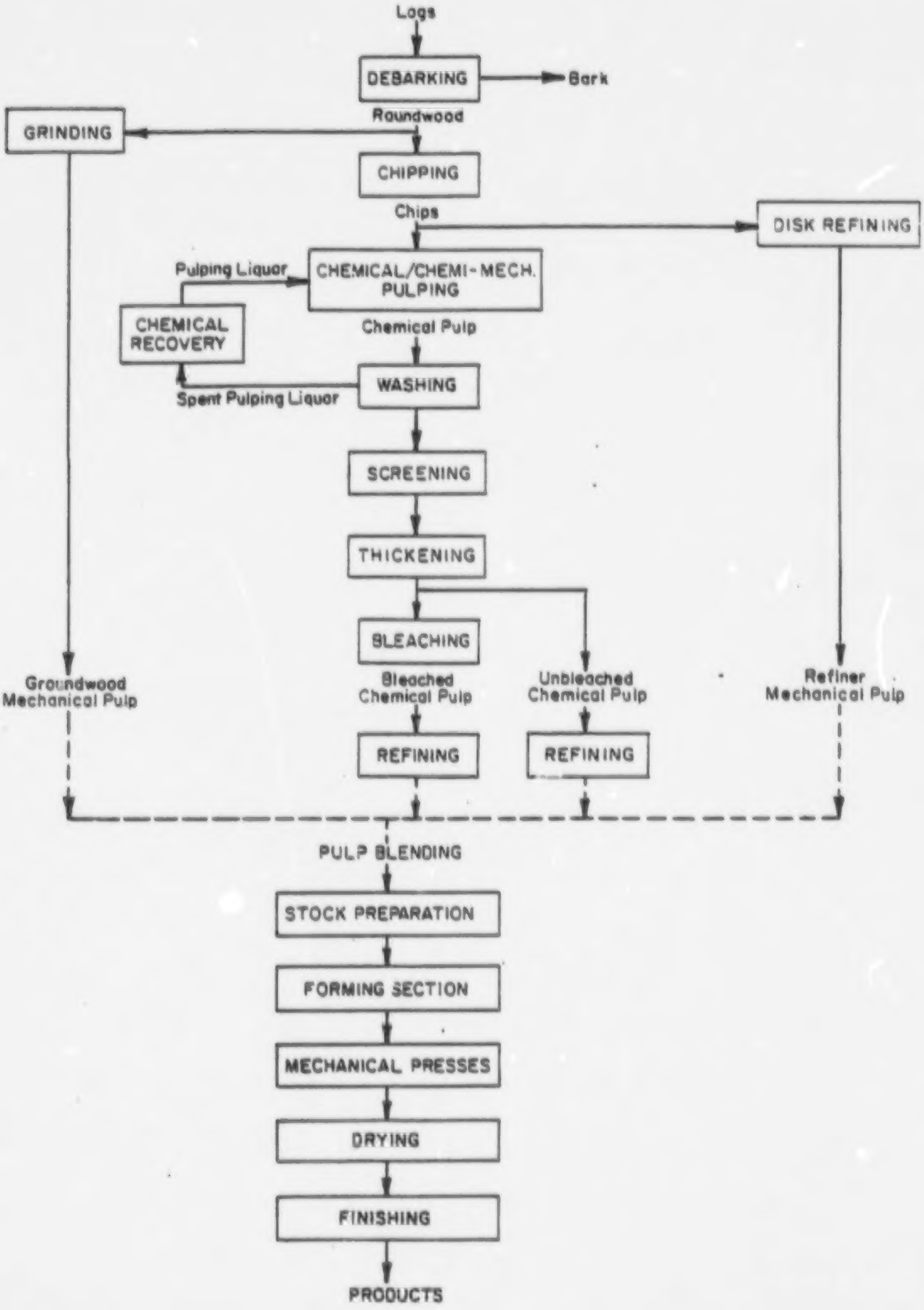
In 1978 lumber mills provided approximately 75 percent of the hog fuel used throughout the province.[19] This hog fuel was mostly in the form of bark, sawdust, shavings and off-cuts. A small part of the hog fuel was used directly by the lumber mills in steam heat dryers and the generation of mechanical and electrical power.

Steam and power demands at lumber mills are rarely compatible because process steam requirements are small and variable. Therefore, little electricity is cogenerated. Larger sawmill operations usually use condensing turbines indicating the incompatibility of steam and electricity loads.

In 1982 the total energy consumption rate per unit of production for Canadian sawmills ranged from approximately 0.6 GJ/m^3 to 2.0 GJ/m^3.[2] This energy consumption rate can be divided into 0.3 to 1.6 GJ/m^3 of thermal energy and 20 to 90 kW·h/m^3 of electrical energy. The thermal energy

Figure 9-1

SCHEMATIC OF PULP AND PAPER PRODUCTION


Logs
DEBARKING
Bark
Roundwood
GRINDING
CHIPPING
Chips
DISK REFINING
Pulping Liquor
CHEMICAL/CHEMI-MECH. PULPING
CHEMICAL RECOVERY
Chemical Pulp
WASHING
Spent Pulping Liquor
SCREENING
THICKENING
BLEACHING
Groundwood Mechanical Pulp
Bleached Chemical Pulp
Unbleached Chemical Pulp
Refiner Mechanical Pulp
REFINING
REFINING
PULP BLENDING
STOCK PREPARATION
FORMING SECTION
MECHANICAL PRESSES
DRYING
FINISHING
PRODUCTS

consumption rate is dependent on the volume of lumber that is kiln dried and its initial and final moisture contents. Other factors that control the electrical and thermal energy consumption rates are lumber species, mill size, mill age and the type of equipment in the mill. For B.C. mills a total energy consumption rate of 1.74 GJ/m^3, a thermal energy consumption rate of 1.53 GJ/m^3 and an electrical energy consumption rate of 58.3 kW•h/m^3 are average (Table 9-1). It is evident from Table 9-1 that most of the energy per unit of product in the forest industry is consumed by the pulp and paper industry.

A summary of purchased energy use in B.C. sawmills and planer mills is listed in Table 9-2.[47] Electricity is approximately 44 percent of the energy used by the B.C. mills.

Lumber dryers and veneer dryers consume 60 percent of the energy used in lumber and plywood manufacture. Heat requirements for drying are approximately 0.68 GJ/m^3 of product.[69] Fuels for drying kilns include natural gas, propane, oil and wood waste. Steam, hot water, indirect hot gas, etc. are used to transmit combustion heat to the kiln. Hog fuel-fired steam boilers are the most common method for kiln drying on the B.C. Coast. Natural gas is the most common fuel for kiln drying at Interior mills where it is available. The drying of veneer and plywood requires 0.6 GJ/m^2 of product at 0.3 cm (3/4 inch) thick. Veneer dryers commonly use natural gas or propane in direct-fired dryers or steam produced by oil, gas and/or hog fuel-fired boilers for indirect-fired dryers.

Table 9-3 summarizes the materials and energy balance for a typical Interior B.C. sawmill.[47] Electrical energy use varies widely from one mill to another depending on the type of equipment. The quantity of wood waste at this typical B.C. sawmill is more than sufficient to supply the 8000 MW•h of electricity and 80 TJ of kiln fuel required by the sawmill. However, sawmills typically have load factors of only 0.5 to 0.6.[2] These low load factors tend to make cogeneration uneconomical.

(b) Cogeneration in the B.C. Wood Products Industry

Although 90 percent of the existing cogeneration in B.C. is in the pulp and paper sector of the B.C. forest industry, there is some existing cogeneration and the potential for further cogeneration in the wood products industry. This information is summarized in Table 9-4. Cogeneration capacity is 26.9 MW, an additional 55 MW is committed. Some of the proposed generation would be from condensing thermal powerplants rather than cogeneration plants.

TABLE 9-1

ENERGY CONSUMPTION IN B.C. FOREST INDUSTRY MILLS*[1]

Mill Type	Electrical Energy Consumption (kW·h/m^3/(GJ/m^3)	Thermal Energy Consumption (GJ/m^3)	Total Energy Consumption (GJ/m^3)	Electrical Thermal Energy Ratio (GJ/GJ)
Pulp and Paper*[2]	861.1 3.10	26.0	29.1	0.119
Sawmill	58.3 0.21	1.53	1.74	0.137
Plywood and Veneer	133.3 0.48	3.03	3.51	0.158
Particle Board	152.8 0.55	1.35	1.90	0.407
Shake and Shingle	69.4 0.25	0.94	1.19	0.266

---

*[1] Based on estimates from the B.C. Utilities Commission.

*[2] Kraft and sulphite mills pre-1982.

*[3] 1 kW·h = 0.0036 GJ.

TABLE 9-2

PURCHASED ENERGY USE FOR BRITISH COLUMBIA SAWMILLS AND PLANER MILLS (1985)*[1,2,3]

	Energy Use (GJ)
Natural Gas	7 806
Light Fuel Oil	73
Heavy Fuel Oil	68
Liquid Petroleum Gas (LPG)	50
Total Fuels	7 997
Purchased Electricity (1592.6 GW·h)	6 311
Total Energy	14 308

---

*[1] Reference: Statistics Canada 1985, Catalogue 57-208.

*[2] Includes only non-motive fuels.

*[3] Heating values:

Natural Gas	37.51 GJ/$10^3$$m^3$
Light Fuel Oil	38.68 MJ/L
Heavy Fuel Oil	41.73 MJ/L
LPG	27.12 MJ/L
Purchased Electricity	3.60 MJ/kW·h

TABLE 9-3

MATERIALS AND ENERGY BALANCE FOR AN INTERIOR B.C. SAWMILL

Nominal Output:*[1]

50 million fbm (118 000 m^3)
@ 480 shifts/year
(surfaced and kiln-dried spruce lumber)

Materials Balance	% log volume	m^3 SWE*[2]
Finished Lumber	40%	80 000
Pulp Chips	38%	76 000
Sawdust	9%	18 000
Shavings	8%	16 000
Chip Fines and Solid Wood Residues	5%	10 000
Total Wood Input	100%	200 000
Bark	10%	20 000

Wood Waste Availability and Characteristics

Component	m^3 SWE*[2]	Oven-Dry Density (kg/m^3)	Weight (ODT)	Higher Heating Value (GJ/ODT)	Moisture Content (Wet Basis)
Sawdust and Other	28 000	360	10 080	19.8	40%
Shavings	16 000	360	5 760	19.8	15%
Bark	20 000	449	8 980	20.3	50%
Total	64 000		24 820		

Energy Requirements

Electricity	67.8 kW·h/m^3	8 000 MW·h/a
Kiln Fuel (natural gas or LPG)	0.68 GJ/m^3	80 TJ/a

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*[1] The nominal output is higher than the actual output of finished lumber because it is based on the nominal, rather than the actual, dimensions of the planed and kiln-dried lumber.

*[2] SWE is Solid Wood Equivalent.

TABLE 9-4

COGENERATION OPPORTUNITIES FOR THE B.C. WOOD PRODUCTS INDUSTRY*[1]

Company or Sector	Location	Forest Region	Generating Capacity (MW)	Additional Generation Potential (MW)
Northwood	Giscome	Prince George	3.9	-
Evans Products	Golden	Nelson	4.0*[2]	-
Hillcrest Lumber	Mesachie Lake	Vancouver	2.4	-
S.M. Simpson	Kelowna	Kamloops	7.3	-
Weldwood	Port Moody	Vancouver	6.5	-
Western Forest	Honeymoon Bay	Vancouver	2.8	-
Total Installed Capacity			26.9	
Northwest Energy*[3]	Williams Lake	Cariboo	-	55.0
Proposed, but Uncommitted:		Vancouver		3.5
		Prince Rupert		93.0
		Prince George		-
		Cariboo		10.0
		Kamloops		48.0
		Nelson		23.5
Total Potential Capacity Proposed				233

---

*[1] The generation is almost exclusively hog-fuel fired (Ref. 71).

*[2] Turbine generator capacity is 7.5 MW.

*[3] Committed hog fuel-fired thermal plant without cogeneration.

9.3 PULP MILLS

(a) Introduction

Wood consists mainly of cellulose (40 to 50 percent) hemicellulose (14 to 35 percent), lignin (15 to 35 percent), a small amount of mineral matter (0.2 to 0.7 percent) and extractives (2 to 8 percent).[44] Cellulose is a polysaccharide which binds together in long chains to form fibres. Hemicellulose is a polysaccharide which is nonfibrous. Lignin is a complex aromatic polymer which cements wood fibres together. Extractives are chemical constituents which give wood its taste, odour and colour. Mineral matter consists of metallic elements which are combined with organic matter or as inorganic compounds.

The production of pulp is the separation of the cellulose from the other constituents of the wood and this can be done by mechanical means, chemical means, or by a combination of the two.[44]

(b) Mechanical Pulping

In the mechanical pulping process, wood is ground and shredded to separate the fibres.[44] The barked logs are pressed against a revolving, roughened, cylinder in the stone ground wood (SGW) and pressure groundwood (PGW) processes, or shredded and ground between the rotating discs of a refiner (refiner mechanical process, RMP).[22] The RMP produces longer fibres than the older SGW process. The Masonite and Asplund Defibrator processes are less common mechanical pulping processes which require chipping and steaming prior to fiberization; these processes are not practised in B.C.[44]

The yield in mechanical pulping is typically about 90 percent. The lignin remains attached to the cellulose and the extractives and part of the hemicellulose is dissolved in the water used in the process.

An average groundwood newsprint mill consumes approximately 6.7 GJ of electricity and 15.5 GJ of process heat per tonne of newsprint.[69]

(c) Chemical Pulping

(i) Introduction

Chemical pulping is a process of chemical treatment of the wood to dissolve the lignin and carbohydrates which bind the fibres together.[44] Chemical pulping produces long, undamaged fibres which are used to make high strength papers.

There are two main processes of chemical pulping:[44] Kraft and sulphite pulping. The kraft process has been the favoured method of chemical pulping since about 1930. Other processes of chemical pulping include methods of solvent pulping which are in the development stage.[48]

(ii) Kraft Pulping

In the kraft process wood chips are cooked in "white liquor", a solution of sodium hydroxide and sodium sulphide (Figure 9-2).[42] This cooking, together with subsequent bleaching and screening, removes the lignin. The resulting "black liquor" is separated from the pulp on a series of washers. The "black liquor" is concentrated by evaporation and subsequently fired in a recovery boiler to produce steam. The sodium salts are recovered from the resulting smelt and used to make the "white liquor". The yield of pulp from the kraft process is typically 40 percent of the oven-dry weight of the source wood.[48,70] The remaining fibre is dissolved in the "black liquor" and burned in the recovery boiler to produce steam and heat.

Many mills use a bàtch process, particularly in the production of kraft pulp.[60] The process requires large quantities of steam for a period of only a few hours. This variability in steam requirements reduces the utilization of the non-condensing turbo-generators. Kraft pulp mills are energy intensive and require 85 percent of their energy as process heat.[6,60] Kraft pulp production has an average energy requirement of 48 GJ/t of wood pulp.[60] Recovery boilers fuelled by lignin (pulp liquor) and hog fuel provide approximately 50 to 60 percent of the heat energy for the pulp and paper industry. In 1982, residual oil provided 17 percent of the energy demand and was the main supplementary fuel in Coastal mills, whereas natural gas provided 12 percent of energy demand and was generally used in Interior mills.

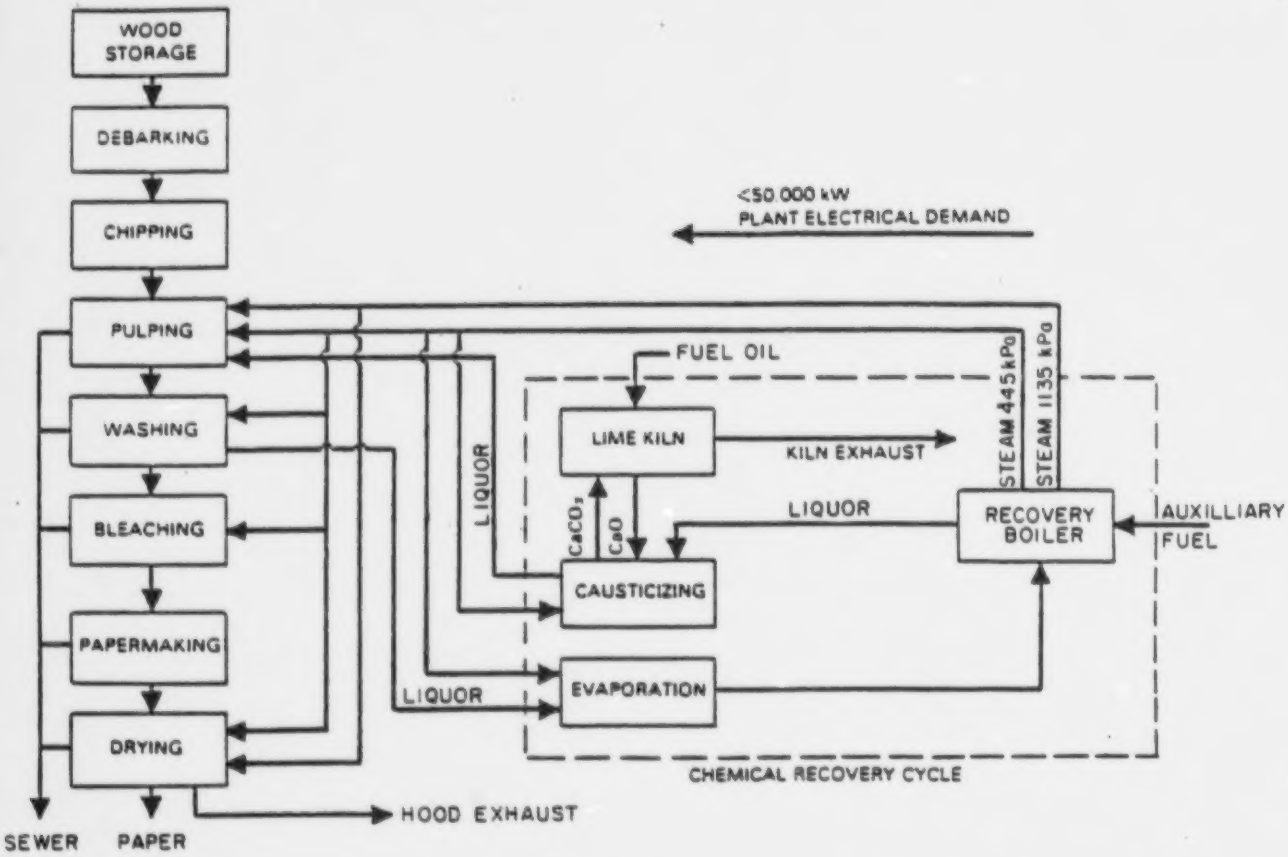
Kraft pulp mills, which require large amounts of process heat (from low pressure steam) compared to electricity (from high pressure steam), could have surplus electricity. However, newsprint mills require large amounts of electricity relative to process heat which encourages the development of integrated facilities.

(iii) Sulphite Pulping

There are two sulphite processes, the neutral sulphite process and the acid sulphite process. The acid sulphite process is the most common. In this process an acidic aqueous solution of magnesium, calcium or ammonium bisulphite and sulphur dioxide is used to "cook" and

Figure 9-2

EXAMPLE OF STEAM AND PULP LIQUOR FLOWS FOR AN INTEGRATED PULP AND PAPER MILL


WOOD STORAGE
DEBARKING
CHIPPING
PULPING
WASHING
BLEACHING
PAPERMAKING
DRYING
SEWER
PAPER
HOOD EXHAUST
<50 000 kW
PLANT ELECTRICAL DEMAND
FUEL OIL
LIME KILN
KILN EXHAUST
STEAM 445 kPa
STEAM 1135 kPa
LIQUOR
CaCO$_3$
CaO
LIQUOR
RECOVERY BOILER
AUXILLIARY FUEL
CAUSTICIZING
EVAPORATION
LIQUOR
CHEMICAL RECOVERY CYCLE

dissolve the lignin binder from the wood, thus freeing the fibre and forming pulp.[48,69] The cooking liquor is prepared from sulphur dioxide and various hydroxides. Subsequently, the pulp is washed and separated from the spent sulphite liquor. The sulphite liquor can be recovered. The washed pulp is screened and usually bleached.

Older sulphite pulp mills using calcium-based pulping solutions did not have recovery systems. However, the change to other pulping solutions (e.g. magnesium-based) has resulted in the installation of recovery boilers in sulphite pulp mills and the potential for cogeneration.

(d) Combinations of Mechanical and Chemical Pulping

(i) Introduction

Combinations of mechanical and chemical pulping were developed to improve fibre recovery and reduce environmental problems associated sulphite pulp production. These methods tend to be more energy intensive because they use more electricity, but this is partly offset by using less process steam. Two recently developed methods of pulping are thermo-mechanical pulping and chemi-thermo-mechanical pulping.

(ii) Thermo-Mechanical Pulping

In the thermo-mechanical pulping (TMP) process, wood chips are steamed under pressure for a few minutes which softens them.[22] They are then passed between two attrition discs to produce fibre, then through a refiner to produce a pulp which is stronger than pulp produced by mechanical pulping methods.

Advantages of the thermo-mechanical pulping process over the mechanical pulping process include the following:[22,69]

1. There are overall cost savings because of a lower requirement for chemical pulp in newsprint manufacture.

2. Potentially cheaper wood sources such as shavings and sawdust can be used.

3. A stronger, more absorbent paper is produced.

A disadvantage of the thermo-mechanical pulping process compared with the mechanical pulping process is the requirement for 80 percent more electrical energy than with the stone groundwood mechanical pulping process.

(iii) Chemi-Mechanical Pulping

Chemi-mechanical pulping is a variation of conventional sulphite pulping in which the chips are partly cooked in a digester and defibering is completed in refiners. The method grades into chemical pulping at one end and mechanical pulping at the other depending on the reliance on chemicals or refiners in the pulping process.

(iv) Chemi-Thermo-Mechanical Pulping

Chemi-thermo-mechanical pulping (CTMP) is a combination of chemical and mechanical pulping as its name implies. Fibres produced by grinding are digested at approximately 160°C in sodium sulphite to produce a pulp.

This method is becoming popular as the cost of wood increases. Fibre recovery is approximately 90 to 95 percent compared with 40 percent for the kraft process.[22,70] CTMP reduces the potential for cogeneration and increases the need for electricity purchases. CTMP has other disadvantages including its soft fibres and low brightness.

(v) Extruded Thermo-Mechanical Pulping

A process of extruded thermo-mechanical pulp (EMP) is under development.*[1] EMP produces stronger pulp with lower specific energy demand than conventional TMP. In the EMP process, the chips are passed through a high compression ratio system which shreds and opens them.

(vi) Stake Explosion Process

The stake explosion pulping process is a developing technology where wood chips are exploded at high temperature and pressure to produce a strong, peroxide bleachable pulp.*[1] This technology is expected to require high thermal demand which may offset its low electrical demand. Although the process is unproven, it could become important.

(vii) Discussion

Until recently newsprint consisted of 75 percent SGW and 25 percent chemically produced (commonly kraft) pulp. Less chemical pulp is required as a result of substituting TMP for SGW. However, the production of SGW requires only 1350 kW·h of electricity per tonne of product compared with 2200 kW·h or more per tonne of product for TMP. CTMP requires slightly less electricity than the production of TMP. However, over 75 percent of the electrical energy used by TMP and CTMP mills ultimately produces steam which could be recovered in dryers and space heating if there was a sufficient requirement.

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[1] Harris, M., Laura Huenemann and George Ionides. 1990. Defining the Potential for Reduced Specific Energy Demand by B.C.'s Pulp and Paper Industry in the 1990's. Report prepared by Temanex Consultants.

Irradiation of wood chips offers a novel method to reduce energy consumption in producing pulp. There may be potential for a 25 percent energy reduction in producing CTMP by using this method (Harris et al, 1990).

(e) Bleaching

The degree of bleaching depends on the end use for the pulp. Most pulp is bleached for whitening and removing additional lignin.[22] Mechanical pulps are bleached with hydrogen peroxide or sodium peroxide. Kraft pulps are bleached by treating with acidic chlorine solutions and combinations of hypochlorite, peroxide and chlorine dioxide. The effect of bleaching on the demand for electricity is listed in Table 9-5.[60,71]

(f) Paper Production

Paper production generally uses one of two papermaking machines: Fourdrinier or cylinder. In both machines a sheet is formed as water drains from the pulp slurry. This sheet, is supported by a fine, moving wire mesh or cylinder. The resulting mat is further dewatered with rollers or presses, dried with heated rollers and finished on calendar rollers. Paper and lightweight cardboards are usually made with Fourdrinier machines and heavy paper and paperboard are often made with cylinder machines.

Energy use in the pulp and paper industry was collected from three sources and this data is summarized in Table 9-5.[60,71] These estimates indicate the high steam demand in kraft paper production and the high electricity demand in producing thermo-mechanical pulp and chemi-thermo-mechanical pulp. Some comparable Canada-wide data for Canadian pulp, paper and newsprint mills are summarized in Table 9-6.[22] From these statistics it is evident that B.C. mills are more efficient, possibly because of mill size or age.

Pulping usually requires steam in the 140 to 175 psig (1065 to 1310 kPa) range, whereas pulp washing, bleaching, furnace evaporators, and paper/paperboard drying and converting require steam in the 50 to 70 psig (415 to 585 kPa) range.[42] For kraft pulp mills, the ratio of low pressure steam for process to high pressure steam for electricity generation is typically higher than for other pulping methods.[60]

TABLE 9-5

ENERGY USE IN THE BRITISH COLUMBIA PULP AND PAPER INDUSTRY*[1]

Product	Electricity Requirements (MW·h/t)[71]	Electricity Requirements (MW·h/t)*[2]	Electricity Requirements (MW·h/t)[60]	Process Steam Requirements (GJ/t)[60]	Total Energy Input (GJ/t)[60]	Electrical Thermal Energy Ratio (GJ/GJ)
Stone Groundwood Pulp	1.8	1.5	-	-	-	-
Thermo-Groundwood Pulp	-	1.6	-	-	-	-
Bleached Kraft Pulp	0.9	-	0.79	28.27	31.11	0.100
Unbleached Kraft Pulp	0.6	-	-	-	-	-
Bleached Sulphite Pulp	0.8	-	-	-	-	-
Unbleached Sulphite Pulp	0.5	-	-	-	-	-
Kraft Paper	1.1	-	1.01	29.49	33.13	0.123
Sulphite Paper	-	-	0.73	16.29	18.92	0.139
Refiner Mechanical Pulp	2.2	1.9	-	-	-	-
Extruded Thermo-Mechanical Pulp*[3]	-	2.3	-	-	-	-
Thermo-Mechanical Pulp	1.8	2.2	2.21	17.45	25.41	0.456
Chemi-Mechanical Pulp	-	0.8	-	-	-	-
Chemi-Thermo-Mechanical Pulp	2.0	1.8-2.3	-	-	-	-
Stake Explosion Pulp*[3]	-	0.8	-	-	-	-
Paper Machine	-	0.75	-	-	-	-
Newsprint	1.5	2.3-2.7*[4]	1.87	10.66	17.39	0.631
Particle Board	0.9	-	1.43	16.29	21.44	0.316
Thermo-Mechanical Newsprint	-	-	2.48	11.63	20.56	0.768
Bleaching of Pulp	0.2	-	-	-	-	-
Drying of Pulp	0.2	-	-	-	-	-
Specialty Paper	-	2.3	-	-	-	-
Newsprint from 50% TMP and 50% Recycled Paper	-	1.4	-	-	-	-

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*[1] This report uses data from Ref. 60 unless data is unavailable.

*[2] Based on estimates in Harris, M., Laura Huenemann and George Ionides. 1990. Defining the Potential for Reduced Specific Energy Demand by B.C.'s Pulp and Paper Industry in the 1990's.

*[3] Emerging technologies.

*[4] The lower value is the electricity requirement for newsprint from 75% SGW/25% kraft and the higher value is the electricity requirement for newsprint from 90% TMP/10% kraft; these estimates include 750 kW·h/t for paper mill demand in each case.

TABLE 9-6

ENERGY USE IN CANADIAN PULP, PAPER AND NEWSPRINT MILLS

Type	1984 Production (kt)	Total Energy Input (PJ)	Total Energy Input (GJ/t)
Kraft Pulp	2832.8	127.2	44.05
Integrated Newsprint/ Sulphite Pulp	4461.0	86.5	19.39

The electrical/thermal energy ratio is variable from one mill type to another, but for the energy intensive pulp and paper industry in 1984 (kraft and sulphite mills) 89 percent of the energy consumption was in the form of process steam.[2]

(g) Energy Requirements for Pulp and Paper Mills

Pulp and paper mills tend to operate approximately 350 days/annum and 24 hours/day. The remaining 15 days allow for scheduled maintenance.[22] Therefore, process heat requirements are continuous, but variable, and electricity load factors are 90 percent or more. However, heat and power demands vary widely from mill to mill because of variations in size, degree of integration, products, equipment age and the amount of energy conservation. Figure 9-2 is an example of steam and pulp liquor flows for an integrated pulp and paper mill.[42] Steam at 445 kPa (50 psig) is used for pulping, washing, bleaching, drying, causticizing and in concentrating the pulping liquor. Steam at 1135 kPa (150 psig) is used for pulping and drying.

Energy use in B.C. pulp and paper mills is summarized in a series of tables. Table 9-7 lists the electricity sources and quantities for B.C. pulp and paper mills. The peak turbogenerator capacities of pulp and paper mills in 1987 are also listed in Table 9-7. As much as 3150 GW·h could be cogenerated at existing installations. From a total of 457 MW only 3 percent of this capacity is in the form of condensing turbines and the remainder is in the form of non-condensing back pressure turbines.

Process steam flows for 1985 are summarized in Table 9-8 it is evident that mechanical drive equipment and pressure reducing valves are still common. Approximately 470 MW of electricity generation could be made available by the elimination of pressure reducing valves, replacement of mechanical drives, the addition of condensing capacity and plant expansions (Table 9-9). This additional generation has been or is being reviewed by the pulp and paper industry in B.C. to determine project economics. This estimate assumes that all of the new generation in condensing. There would be approximately a 50 percent reduction in generating capacity for any cogeneration capacity from these projects.

Mills with limited process steam flows, and therefore, limited cogeneration include Finlay Forest Industries, TMP mills at Taylor and Quesnel and four small mills in the Lower Mainland (Scott Paper, Annacis Island, Canadian Forest Products and Paperboard Industries).

(h) Future Additions to Pulp, Paper and Generating Capacity

Thermo-mechanical and Chemi-thermo-mechanical pulp mills and newsprint mills are expected to dominate mill expansions and

TABLE 9-7

ENERGY USE IN B.C. PULP AND PAPER MILLS*[1]

Company	Location	Forest Region	Energy Source	Capacity (MW)	Self-Generated Electricity (MW·h/d)*[3]	Electricity Purchased (MW·h/d or %)
Canadian Forest Products:						
Intercontinental Pulp	Prince George	Prince George	Gas/Hog	-	-	100%
Prince George Pulp	Prince George	Prince George	Oil/Gas/Hog	-	-	600
Canadian Pacific	Gold River	Vancouver	Oil/Hog	25	510	1010
Cariboo Pulp & Paper	Quesnel	Cariboo	Gas/Oil/Hog	28	570	375
Celgar Pulp	Castlegar	Nelson	Oil/Gas/Hog	3	60	360
Crestbrook Forest Industries	Skookumchuck	Nelson	Gas	15	300	0%
Eurocan	Kitimat	Prince Rupert	Gas/Hog	-	-	100%
Fibreco Export	Taylor	Prince George	Gas	-	-	100%
Finlay Forest Products	Mackenzie	Prince George	Gas	-	-	100%
Fletcher Challenge:	Campbell River	Vancouver	Oil/Hog	29	590	2630
	Crofton	Vancouver	Oil/Hog	38.5	790	2270
	Mackenzie	Prince George	Gas/Hog	20	410	420
	New Westminster	Vancouver	Gas	3.4	-	100%
Howe Sound Pulp and Paper	Port Mellon	Vancouver	Oil/Hog	3	60	325
Island Paper	New Westminster	Vancouver	Gas	4.3	-	80

TABLE 9-7 - (Cont'd)

Company	Location	Forest Region	Energy Source	Capacity (MW)	Self-Generated Electricity (MW·h/d)*[3]	Electricity Purchased (MW·h/d or %)
MacMillan Bloedel:	Nanaimo	Vancouver	Oil/Hog	36.75	750	240
	Port Alberni	Vancouver	Oil/Hog	30	610	1800
	Powell River	Vancouver	Oil/Hog	54	1100	2270
Northwood Pulp & Timber	Prince George	Prince George	Gas/Oil/Hog	56.8	990	245
Paperboard Industries	Burnaby	Vancouver	MSW*[2]	-	-	350
Quesnel River Pulp	Quesnel	Cariboo	-	-	-	100%
Scott Paper	New Westminster	Vancouver	Gas/Hog	-	-	100%
Skeena Cellulose	Prince Rupert	Prince Rupert	Gas/Oil/Hog	40	820	320
Western Pulp Partnership:	Port Alice	Vancouver	Oil/Hog	27.6	560	0%
	Woodfibre	Vancouver	Oil/Hog	7	140	335
Weyerhaeuser	Kamloops	Kamloops	Gas/Oil/Hog	36	730	210
TOTAL				457	>7235	

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*[1] Lockwood Posts Directory, Pulp and Paper Mills in Canada, British Columbia; Ref. 70.

*[2] Steam is purchased from the Greater Vancouver Regional District's municipal solid waste (MSW) plant. The steam is not used for electricity generation.

*[3] Estimates are based on published information; B.C. Hydro files were not used because they are privileged. Assumed 85% capacity factor unless other information is available. Much of the steam for power generation is derived from recovery boilers.

TABLE 9-8

STEAM FLOWS IN B.C. PULP AND PAPER MILLS

Company	Location	Steam Flow (kg/h)	Pressure (psi/kPa)	Product
Canadian Forest Products:				
Intercontinental Pulp	Prince George	205 000	600/4240	640 t/d bleached & unbleached kraft pulp
Prince George Pulp	Prince George	113 000	600/4240	295 t/d kraft sack paper 495 t/d kraft pulp
Canadian Pacific Forest Products	Gold River	240 000	600/4240	750 t/d bleached kraft pulp 225 t/d newsprint
Cariboo Pulp & Paper	Quesnel	277 000	600/4240	1080 t/d bleached kraft pulp and thermo-mechanical pulp
Celgar Pulp	Castlegar	225 000	600/4240	600 t/d bleached and semi-bleached kraft pulp
Crestbrook Forest Industries	Skookumchuck	91 000	600/4240	575 t/d bleached kraft pulp
Eurocan	Kitimat	180 000	600/4240	1120 t/d linerboard Clupak extensible paper 300 t/d chemi-mechanical pulp
Fibreco Export	Taylor	30 900	-	500 t/d bleached chemi-thermo-mechanical pulp
Finlay Forest Products	Mackenzie	60 000	-	450 t/d groundwood pulp, newsprint
Fletcher Challenge:	Campbell River	455 000	600/4240	1150 t/d newsprint 120 t/d kraft bags 140 t/d linerboard 590 t/d bleached kraft pulp
	Crofton	345 000	600/4450	800 t/d bleached, unbleached & semi-bleached kraft pulp 1330 t/d newsprint

TABLE 9-8 - (Cont'd)

Company	Location	Steam Flow (kg/h)	Pressure (psi/kPa)	Product
Fletcher Challenge: (Cont'd)	Mackenzie	160 000	-	580 t/d bleached kraft pulp 200 t/d newsprint
	New Westminster	-	600/4240	200 t/d hardboard
Howe Sound Pulp	Port Mellon	68 200	400/2840	650 t/d bleached & unbleached kraft pulp
Island Paper	New Westminster	30 000	400/2560	400 t/d bleached paper
MacMillan Bloedel:	Nanaimo	470 000	600/4240	1250 t/d bleached kraft pulp
	Port Alberni	455 000	675/4755	1220 t/d newsprint 220 t/d unbleached kraft pulp
	Powell River	750 000	900/6310, 600/4240	1750 t/d newsprint and other papers 150 t/d semi-bleached kraft pulp
Northwood Pulp & Timber	Prince George	500 000	600/4240	1100 t/d bleached kraft pulp
Paperboard Industries	Burnaby	78 000	400/2560	525 t/d roofing felt, linerboard, gypsum wallboard, core stock, sheathing paper
Quesnel River Pulp	Quesnel	21 000	-	830 t/d thermo-mechanical and chemi-thermo-mechanical pulp
Scott Paper	New Westminster	-	600/4240	Specialty papers
Skeena Cellulose	Prince Rupert	480 000	600/4240	1440 t/d bleached kraft pulp
Western Pulp Partnership:	Port Alice	209 000	600/4240	450 t/d sulphite pulp
	Woodfibre	191 000	600/4240	630 t/d semi-bleached and bleached kraft pulp
Weyerhaeuser	Kamloops	950 000	600/4240	1250 t/d bleached and semi-bleached kraft pulp

TABLE 9-9

CAPACITY AND POSSIBLE CAPACITY ADDITIONS TO B.C. PULP AND PAPER MILLS

Capacity:

Company	Location	Installed Capacity (MW)
Canadian Forest Products:		
Prince George Pulp	Prince George	-
Intercontinental Pulp	Prince George	-
Canadian Pacific Forest Products	Gold River	25
Cariboo Pulp and Paper	Quesnel	28
Celgar Pulp	Castlegar	3
Crestbrook Forest Industries	Skookumchuck	15
Eurocan	Kitimat	-
Fibreco Export	Taylor	-
Finlay Forest Products	Mackenzie	-
Fletcher Challenge:	Campbell River	29
	Crofton	38.5
	Mackenzie	20
	New Westminster	3.4
Howe Sound Pulp & Paper	Port Mellon	3
Island Paper	New Westminster	4.3
MacMillan Bloedel:	Nanaimo	36.75
	Port Alberni	30
	Powell River	54
Northwood Pulp & Timber	Prince George	56.8
Paperboard Industries	Burnaby	-
Quesnel River Pulp	Quesnel	-
Scott Paper	New Westminster	-
Skeena Cellulose	Prince Rupert	40

TABLE 9-9 - (Cont'd)

Capacity:

Company	Location	Installed Capacity (MW)
Western Pulp Partnership:	Port Alice	27.6
	Woodfibre	7
Weyerhaeuser	Kamloops	36
TOTAL INSTALLED CAPACITY		457
ADDITIONAL GENERATING CAPACITY (MW)		
Committed: Howe Sound Pulp & Paper Expansion	Port Mellon	85
Proposed but Uncommitted Capacity Additions:*[1]	Forest Region	
	Vancouver	137
	Prince Rupert	80
	Prince George	88
	Cariboo	10
	Kamloops	36
	Nelson	35
TOTAL PROPOSED CAPACITY ADDITIONS		471

---

*[1] Includes possible boiler, turbine generator, condensing capability and steam drive and pressure reducing valve replacement. Many of these possible capacity additions may not be economic after further review.

new mill construction. Table 9-10 summarizes the distribution by product of present and projected pulp and paper production in B.C. over the next decade.[70] The newsprint mills in B.C. are integrated with pulp mills and share energy sources.[69]

A few expansions and improvements are underway. They include Fletcher Challenge at Crofton which is upgrading to produce an additional 200 t/d of kraft pulp and 250 t/d of thermomechanical pulp. Howe Sound Pulp and Paper is expanding to 1000 t/d of bleached, semi-bleached and kraft market pulp as well as 535 t/d of newsprint. Howe Sound Pulp and Paper is also expanding its generating capacity by more than 80 MW.

As noted in Section 6.4, the availability of hog fuel could be a factor affecting further development of hog fuel-fired cogeneration or condensing generation. Potential shortages of hog fuel were identified in the Vancouver and Prince Rupert Forest Regions by 1995.*[1] The present capacity of wood-fired generation in B.C. is 462 MW,*[2] of which 435 MW is at pulp mills and the remainder is at sawmills. There is 85 MW of new cogeneration capacity which is committed at Port Mellon. An additional 55 MW of thermal power generation is committed at Williams Lake. Other proposed projects total 564 MW (Table 9-11). By comparison there is a total potential for 809 MW of new wood-fired generating capability based on an 85 percent capacity factor and the utilization of all of the sawmill/pulp mill wood waste produced in B.C. The estimates of available capacity and energy assume that the new generation is for condensing thermal power generation. If the wood waste was used for cogeneration only about half of that capacity and energy would be available.

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[1] Based on information from Stewart & Ewing Associates Ltd. 1990. Provincial Wood Waste Supply and Utilization Study. Report completed for B.C. Hydro.

[2] Note that approximately 22 MW of capacity at pulp mills is exclusively gas or oil fired.

TABLE 9-10

PRODUCT DISTRIBUTION IN THE PULP AND PAPER INDUSTRY IN B.C. (1987-1997)

Product	Year 1987	Year 1997
Market Pulp	60.7%	49.1%
Newsprint	24.8%	31.8%
Specialty Products	12.0%	12.4%
Chemo-Thermo Mechanical Pulp	2.5%	6.7%
Total	100%	100%

TABLE 9-11

ELECTRICITY GENERATION FROM WOOD WASTE

Forest Region	Present Capacity (MW)	Present Potential Thermal Self-Generation*[1] (GW·h)	Proposed Capacity (MW)	Proposed Energy (GW·h)	Available Capacity (MW)	Available Energy (GW·h)*[2]
Vancouver*[3]	263	1960	141	1046	122	708*[4]
Prince Rupert	40	300	173	1289	97	621
Prince George	81	600	88	655	242	1801
Cariboo*[5]	28	210	20	149	78	580*[6]
Kamloops	43	320	84	626	116	865
Nelson	7	50	58	436	154	1148
TOTAL	462	3440	564	4201	809	5723

---

*[1] Assumes an 85 percent capacity factor. Approximately 45 percent of the steam for power generation at pulp mills is derived from recovery boilers. Excludes natural gas and oil-fired generation at pulp mills, but includes wood-fired generation at sawmills.

*[2] Assumes all new generation is condensing. Condensing generation would require approximately one-half as much fuel as cogeneration for each unit of electricity generation.

*[3] Excludes new, committed electricity generation at Port Mellon (85 MW and 700 GW·h per annum). Approximately 80 percent of the wood waste in this region is in the Chilliwack Forest District, along the Fraser River.

*[4] Fuel for Port Mellon has been subtracted to arrive at the available energy.

*[5] Excludes new, committed electricity generation at Williams Lake as well as removal of wood waste for use in the proposed fibreboard plant. The new generating plant will have a capacity of 55 MW and annual electricity generation of 438 GW·h.

*[6] Fuel for the thermal and fibreboard plants at Williams Lake was subtracted to arrive at the available energy.

SECTION 10.0 - COGENERATION IN B.C. OUTSIDE OF THE FOREST INDUSTRY

10.1 INTRODUCTION

Cogenerators in B.C., but outside of the forest industry use diesel, gas turbine and potentially gas turbine combined cycle technologies. Heat can be recovered from the exhaust and, with a diesel engine, from the cooling system as well.

10.2 DIESEL ENGINE GENERATION

The thermal efficiency of a diesel engine varies with load and engine size. A typical range of efficiencies at various loads is illustrated in Figure 10-1.[2] Efficiencies are as high as 30 to 35 percent at high loads and 15 to 20 percent at low loads. Diesel engines must be derated by 25 to 30 percent if fired on wood gas. On the B.C. Hydro system, the efficiency of diesel engine generation over a one-year period ranges from 27 percent for small units below 1,300 kW to 31 percent for larger units with capacities of more than 5000 kW.[72]

The distribution of energy losses for diesel engine generation at full load and at low load are illustrated in Figs. 10-2 and 10-3 respectively.[2] In both figures most of the losses are in the exhaust and coolant. The distribution of energy losses and recovery for diesel electric generating stations at full load are listed in Table 10-1 for a diesel engine generation with and without cogeneration. It is feasible to recover 70 percent of the sensible heat in the coolant as well as the heat in the exhaust. Therefore, energy efficiency for diesel generation is approximately 30 percent without cogeneration and 80 percent with cogeneration.

10.3 DIESEL ENGINE COGENERATION

Cogeneration systems with diesel engines include direct, indirect and indirect combined cycle.[62] For direct diesel engine topping cycles, hot exhaust gases are used for process heating or drying or for preheating combustion air for a boiler. Indirect applications use hot water from the cooling system in a heat exchanger and/or process steam produced from exhaust gases in a waste heat boiler. Indirect/combined cycle applications use exhaust heat in a waste heat boiler to produce process steam. Figure 10-4 is a schematic of a diesel engine cogeneration system producing steam for a process, hot water for heating and electricity.[67]

The potential uses of waste heat from a diesel cogeneration system are a function of temperature. The temperature of diesel exhaust gases is usually between 260°C and 510°C which is lower than the temperature of exhaust gases from gas turbines.[42] Steam pressure from associated waste heat boilers is usually less than 2860 kPa and can be less than 1430 kPa (@ 340°C).

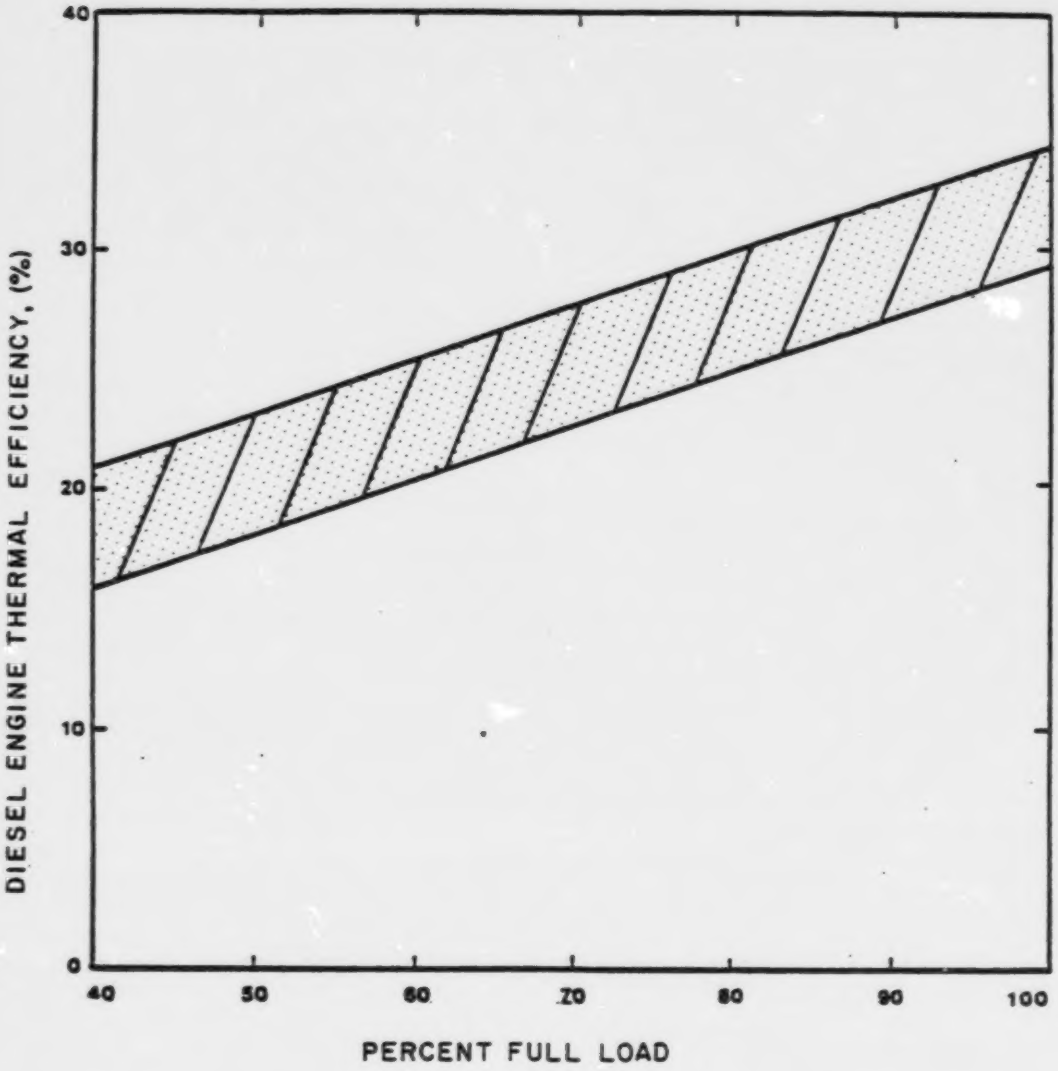


Figure 10-1

TYPICAL DIESEL ENGINE THERMAL EFFICIENCY AT VARIOUS LOADS

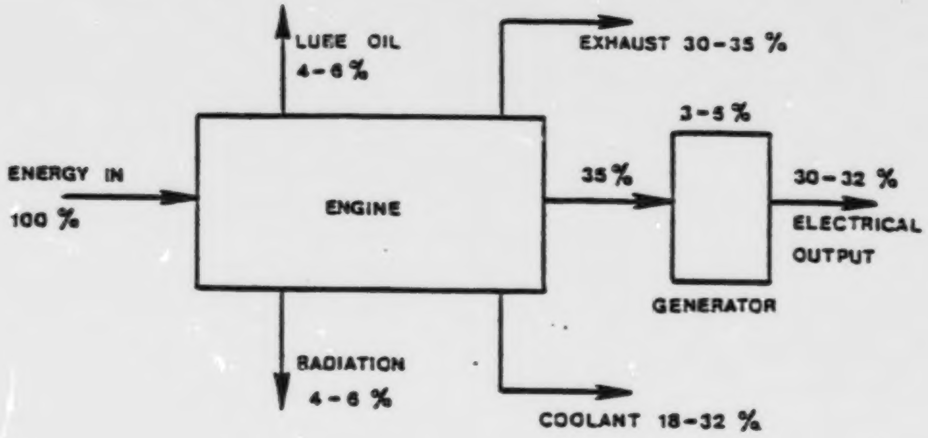

LUBE OIL
4-6 %
EXHAUST 30-35 %
3-5 %
ENERGY IN
100 %
ENGINE
35 %
30-32 %
ELECTRICAL
OUTPUT
GENERATOR
RADIATION
4-6 %
COOLANT 18-32 %

Figure 10-2

TYPICAL ENERGY BALANCE FOR
DIESEL ENGINE GENERATION AT FULL LOAD

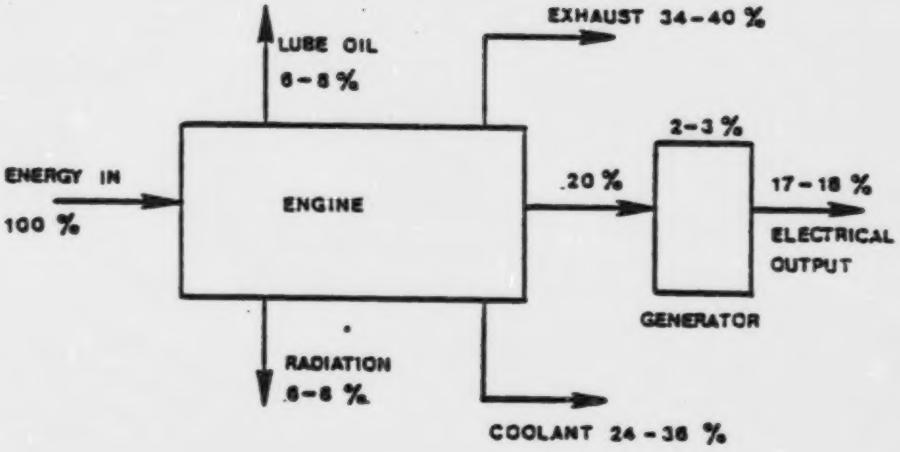

LUBE OIL
6-8 %
EXHAUST 34-40 %
2-3 %
ENERGY IN
100 %
ENGINE
20 %
17-18 %
ELECTRICAL
OUTPUT
GENERATOR
RADIATION
6-8 %
COOLANT 24-36 %

Figure 10-3

TYPICAL ENERGY BALANCE FOR
DIESEL ENGINE GENERATION AT LOW LOAD

TABLE 10-1

ENERGY BALANCE FOR DIESEL ELECTRIC GENERATION*[1]

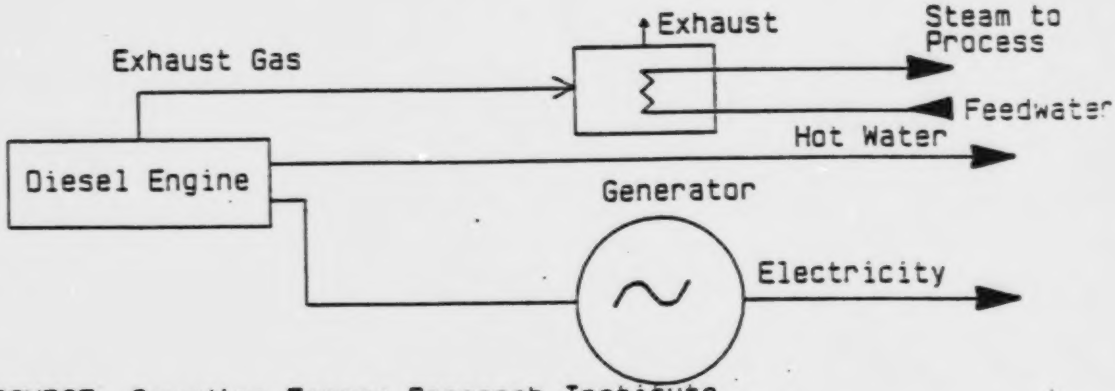
	Without Cogeneration	With Cogeneration
Electricity	+30	+30
Exhaust	-30	+20
Coolant	-30	+30
Radiation, Lube Oil and Generator Energy Available for Recovery	-10	-20
Total Recoverable Energy	+30	+80

---

*[1] Recoverable energy (+)
Waste energy (-)

Figure 10-4

DIESEL ENGINE COGENERATION SYSTEM


Exhaust
Steam to Process
Exhaust Gas
Feedwater
Hot Water
Diesel Engine
Generator
Electricity

SOURCE: Canadian Energy Research Institute.

Therefore, supplementary firing is commonly used. Hot water from the cooling system can be used for space and process heating.

Diesel engine cogeneration produces a high electricity/thermal energy ratio. An example of the variation in electrical/thermal energy ratios for a caterpillar engine are illustrated in Figure 10-5.[2] The power-to-heat ratio of diesels at full load ranges from 332 to 663 kW·h/GJ. The reject heat from the exhaust gas would only be expected to produce 18 000 to 23 000 kg/h of steam from the largest diesel engines, i.e. those in the 25 to 30 MW range. However, the steam production can be increased with supplementary firing.

10.4 GAS TURBINES

A gas turbine operates on a Brayton cycle and consist of three components: compressor, pressurized combustor and expansion turbine. The work applied to the compressor reduces the overall efficiency of the turbine.[2] The compressor and turbine can be arranged in an axial or a radial flow design. The axial flow arrangement is more efficient and operates at higher temperatures and pressures, but the radial flow arrangement is more rugged, easily modified for low temperature gases and less susceptible to corrosion or erosion. Gas turbines can be used alone in a simple cycle or with a steam turbine in a combined cycle.

Gas turbines can operate on natural gas, diesel, crude oil, residual fuel oil or synthesis gas, the latter made from coal or wood.[42] Maximum availability and reliability are obtained with natural gas. Overall availability can be as high as 97 percent.

For biomass-fueled gas turbines, the combustor is usually separate from the turbine-compressor unit because of the tarry nature of the biomass-derived combustion gases.[2] An internal combustor is also included for start-up and back-up capabilities.

10.5 GAS TURBINE COGENERATION

Gas turbine cogeneration plants are second to steam turbine cogeneration plants in popularity. High pressure steam produced in the combustor passes through the turbine and low pressure steam goes to the process. Electrical efficiencies for gas turbines range from 20 to 40 percent. Gas turbines have the following advantages for cogeneration:

1. Easy to transport.
2. Easy to install.
3. Short lead times.
4. Respond quickly to changes in load.

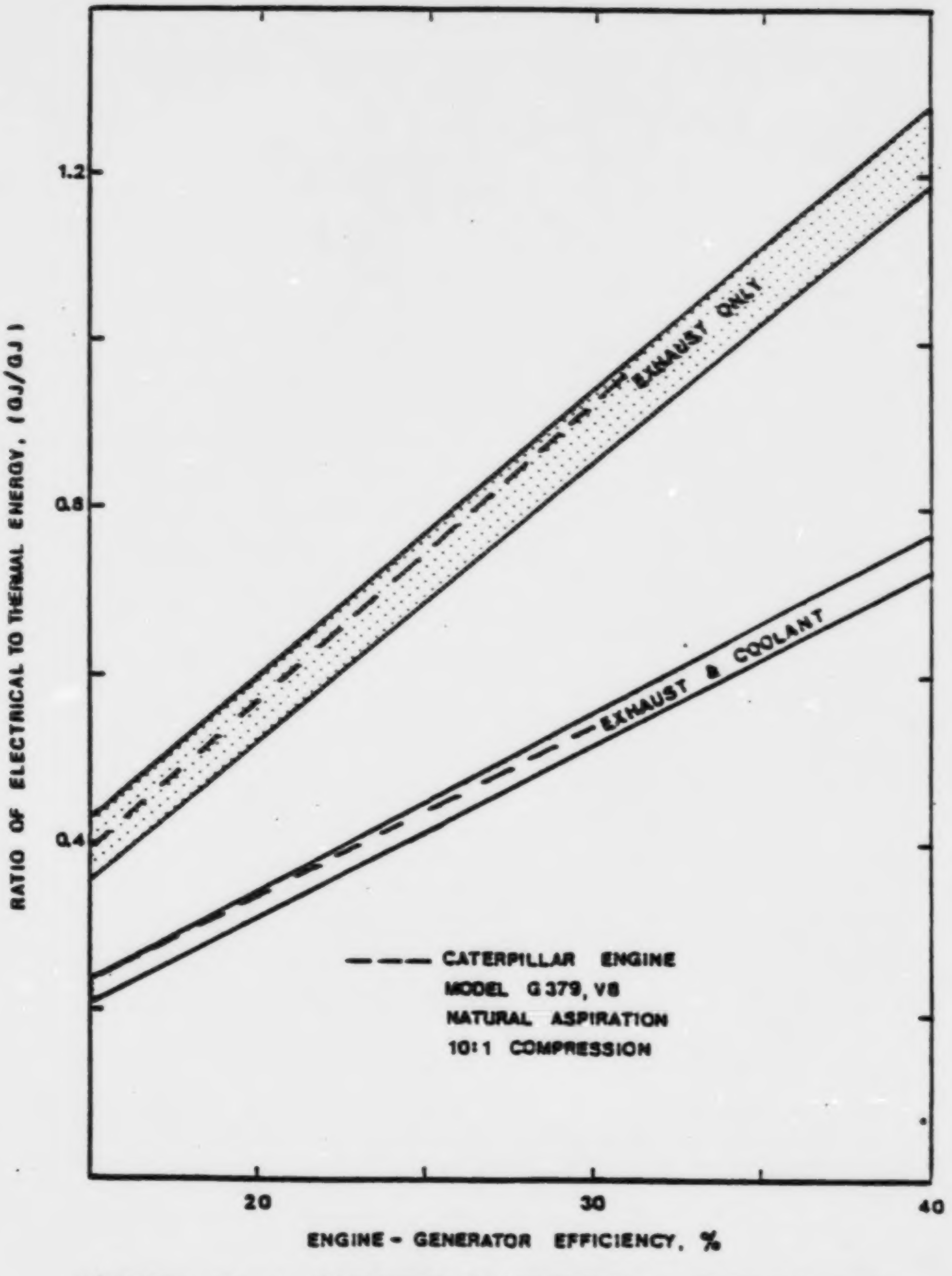


FIGURE 10-5 ELECTRICAL / THERMAL ENERGY FOR INTERNAL COMBUSTION ENGINES

Gas turbines are used in direct, indirect and indirect/combined-cycle cogeneration systems. Direct applications with gas turbines are comparable to direct applications with diesel engines. In a direct gas turbine topping cycle, the hot exhaust gases from the turbine are used directly for process heating and drying or as preheated combustion air in boilers.[42] In an indirect system the energy from the hot turbine exhaust gases is recovered in a waste heat boiler which produces process steam (Figure 10-6).[67] In combined cycle gas/steam turbine cogeneration, heat is recovered from the hot exhaust to produce steam in a waste heat boiler; the steam is subsequently expanded through a back pressure steam turbine to yield steam and electricity, possibly with supplementary firing to produce steam at higher pressure and hence more electricity.

In indirect gas turbine systems, power-to-heat ratios range from approximately 133 to 213 kW·h/GJ.[42] At full load electric efficiencies range from 24 to 35 percent, while at 50 percent partial load, efficiencies range from 19 to 29 percent. Indirectly heated gas turbines produce about 5 percent less power than a similar directly heated gas turbine because the former has no fuel mass flow and a lower turbine exhaust temperature.[2] A typical schematic of the energy balance at full power is illustrated in Figure 10-7.

Gas turbine cycles can be open, closed or regenerative. Open gas turbine cycles have heat rates of 5500 to 6000 kJ/kW·h when the exhausted thermal energy is used by the process.[2] Electrical to thermal energy output ratios are typically in the range of 0.10 to 0.55. Open cycle gas turbines have lower conversion efficiencies and lower exhaust temperatures because they must operate at partial load by reducing the turbine inlet temperature.[2] Conversely, closed cycle gas turbines obtain partial load by varying system pressure (i.e. mass flow) while maintaining the turbine inlet temperature; an over-sized heat exchanger improves cycle efficiency. Electrical to thermal output ratios are in the range 0.10 to 0.75 for a regenerative cycle where the compressed air temperature is increased prior to entering the combustor.[2] A regenerative cycle is not advantageous with a combined cycle plant.

10.6 GAS TURBINE COMBINED CYCLE COGENERATION

Gas turbine combined cycle plants commonly use premium fuels such as natural gas, but they can achieve electrical efficiencies of 40 to 48 percent as well as supply process heat.[67] Power-to-heat ratios for combined cycle systems typically range from 166 to 303 kW·h/GJ.[42] A schematic of a gas turbine combined cycle cogeneration system is illustrated in Figure 10-8. Combined cycle plants are associated with large industrial complexes which are common in the chemical and petroleum refining industries. The development of coal gasification technology with combined cycle plants could improve their economics and versatility if natural gas prices should increase markedly.

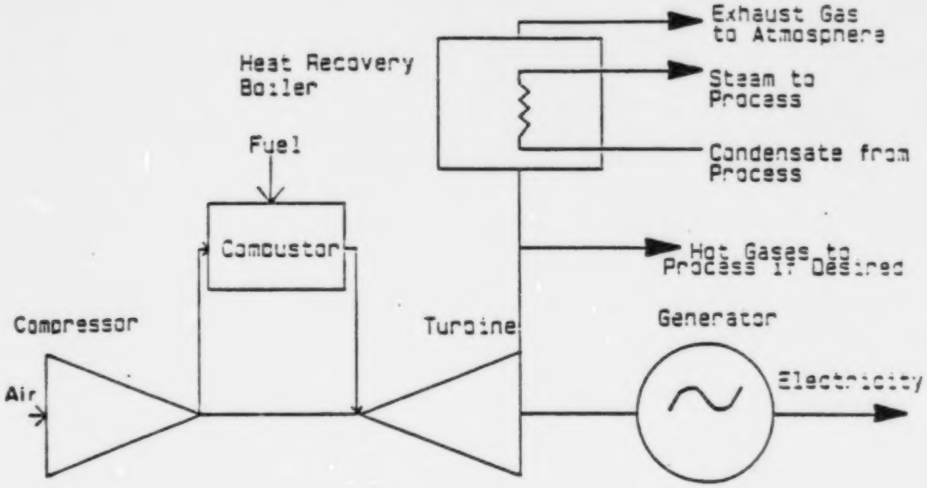

Exhaust Gas to Atmosphere
Heat Recovery Boiler
Steam to Process
Fuel
Condensate from Process
Combustor
Hot Gases to Process if Desired
Compressor
Turbine
Generator
Air
Electricity

Figure 10-6

INDIRECT GAS TURBINE COGENERATION SYSTEM

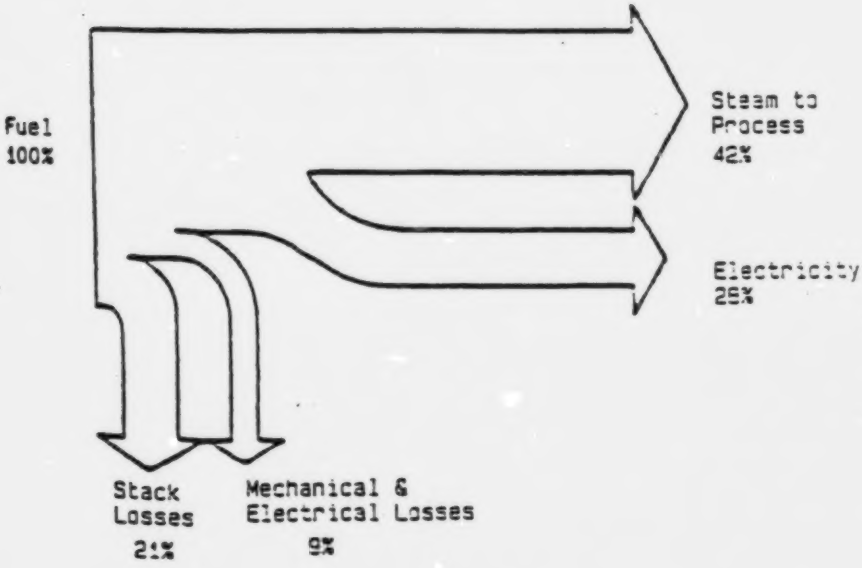
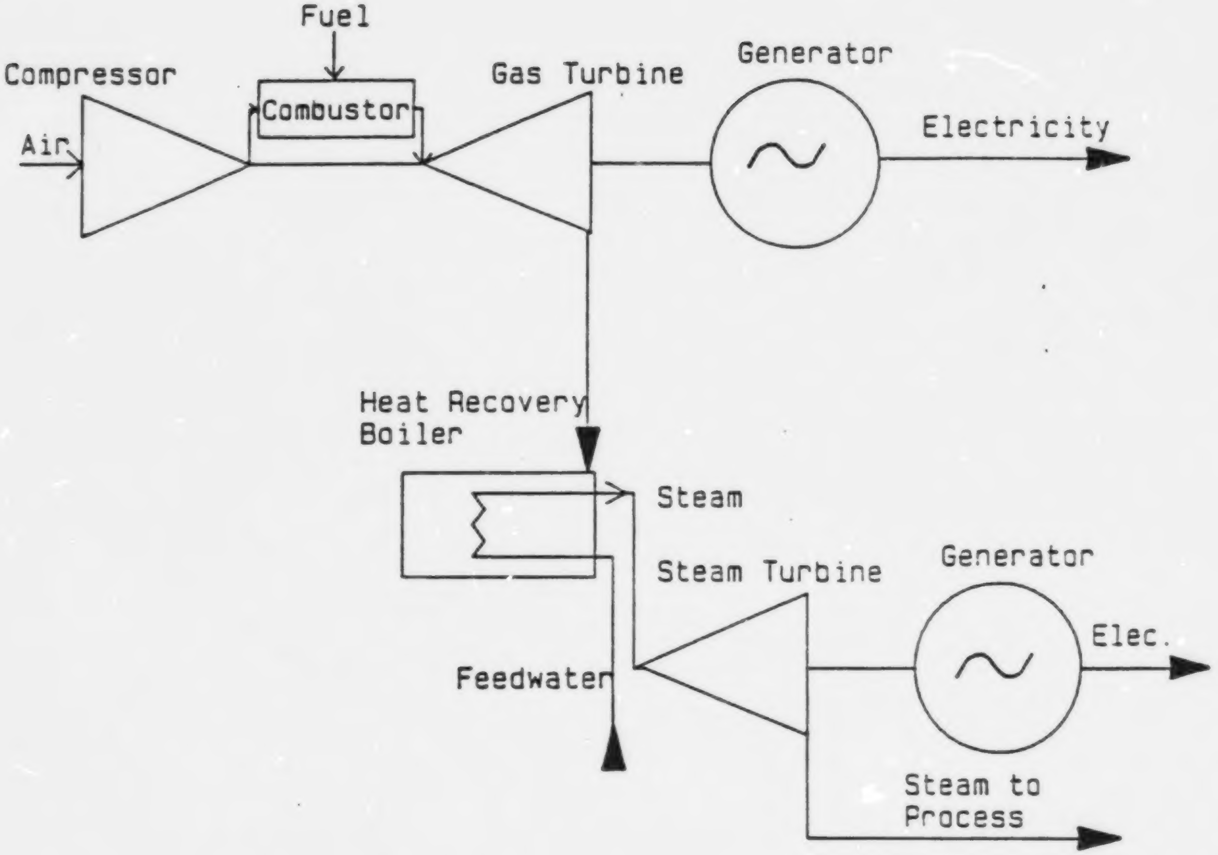


Figure 10-7

ENERGY BALANCE FOR A GAS TURBINE COGENERATION SYSTEM

Figure 10 - 8

COMBINED CYCLE COGENERATION SYSTEM


Fuel
Compressor
Combustor
Gas Turbine
Generator
Air
Electricity
Heat Recovery
Boiler
Steam
Steam Turbine
Generator
Elec.
Feedwater
Steam to
Process

10.7 COGENERATION IN B. C.

Although 96 percent of the existing cogeneration in B.C. is in the forest industry, there is existing cogeneration and considerable potential for further cogeneration from other industries and facilities. These cogeneration opportunities are summarized in Table 10-2. There is 21.6 MW of existing cogeneration outside of the forest industry and approximately 550 MW of proposed cogeneration. Most of this cogeneration would require some condensing capability and some, such as Westcoast Energy at Taylor, would use a bottoming cycle. Coal mines could provide an opportunity for topping cycle gas turbine operation where the electricity would supply the mine and the exhaust would be used for coal drying.

10.8 DISCUSSION

In Chapters 9.0 and 10.0 several technologies for cogeneration are described. Table 10-3 summarizes some characteristics which are typical of steam turbine, gas turbine, gas turbine/combined cycle and diesel engine cogeneration.[67] The efficiencies assume fossil fuel firing.

TABLE 10-2

COGENERATION OPPORTUNITIES FOR B. C. OUTSIDE OF THE FOREST INDUSTRY

Company or Sector	Location	Present Generating Capacity (MW)*[1]	Additional Generation Potential (MW)
Lower Mainland Refineries	Greater Vancouver	-	25
Westcoast Energy*[2]	Fort Nelson	5.9	100
Westcoast Energy	Taylor	5	95
Husky Oil	Prince George	-	5
B. C. Sugar	Vancouver	5.5	-
Vancouver General Hospital	Vancouver	5.2	-
Total Installed and Proposed Capacity		21.6	225
Other Cogeneration and Self-Generation Opportunities			310-340
Total Potential Capacity Proposed and Estimated			535-565

(References: 59,71)

Notes:

*[1] With the exception of generation from the refineries where by-product oil is used, the existing and new generation is natural gas.

*[2] Off grid.

TABLE 10-3

COMPARISON OF CONVENTIONAL TOPPING-CYCLE TECHNOLOGIES

Features	Steam Turbine Cogenerator	Gas Turbine Cogenerator	Gas Turbine Combined Cycle Cogenerator	Diesel Engine Cogenerator
Unit Size (MW)	.5 up	.1-200	3-400	.075-30
Fuels Used*[1]	Any	Natural Gas Distillates	Natural Gas Distillates	Natural Gas Distillates Residual Oil
Availability (%)	90-95	90-95	77-95	80-90
Installation Lead Time (years)	Typically 1-5	0.75-2	1-3	0.75-2.5
Service Life (years)	25-35	15-20	15-25	15-25
System Efficiency (%)	65-85	65-85	65-85	40-80
New Heat Rate (kJ/kW•h)	4200-6300	5800-6300	5300-6900	6300-7900
Electrical Efficiency (%)	15-30	25-35	35-48	35-40
Electricity-to-Steam Ratio (kW•h/GJ)	30-75	140-225	175-320	350-700
Installed Capital Cost ($/kW 1985)*[2,3]	705-2320	625-1235	310-920	N/A*[4]
Environmental Emissions	SOx, NOx	NOx	NOx	NOx, CO
Applicability	Most common technology. Best suited for low power/steam requirements.	Also common technology. Main goal is power generation.	Used in large industrial applications. Best suited for high power/steam requirements.	Highest power/steam ratio. Best for small cogenerators and space heating.

*[1] Excludes potential fuels.
*[2] Refers to "typical" system costs.
*[3] Assumes an exchange rate of $0.85 U.S. = $1.00 Canadian.
*[4] Depends on the degree of cogeneration (exhaust and/or cooling water).

SECTION 11.0 - ENVIRONMENTAL FACTORS

11.1 INTRODUCTION

Environmental concerns arising from cogeneration include air emissions, water contamination, air borne dust, land alienation, removal of wildlife habitat, and visual impacts. These concerns may be partly reduced because cogeneration is often associated with a large industrial facility (e.g. pulp and paper mill) and the incremental effect may not be as significant as building the cogeneration plant in a pristeen environment.

Of particular concern are the emissions of air contaminants, water effluents and solid wastes. The provincial Waste Management Act (1982) defines the process whereby wastes are controlled when released to the environment.

11.2 AIR EMISSIONS

Potential air emissions from a cogeneration plant include nitrogen oxides (NO_x), sulphur dioxide (SO_x), carbon dioxide/carbon monoxide, hydrocarbons, trace elements and particulates.[42] A comparison of typical emissions for controlled and uncontrolled burning is summarized in Table 11-1.

Nitrogen oxides are formed from the fuel and the combustion air. The quantity of NO_x in the flue gases depends mostly on the combustion temperature. High temperatures promote the formation of NO_x and below 800°C much less NO_x are formed. The use of fluidized bed combustion technology with a low bed temperature could be used to reduce NO_x. Other modifications which can be used with coal, oil or gas-fired boilers to reduce NO_x include the following:

1. Low excess air.
2. Staged combustion air by adding overfire air or sidefire air.
3. Low NO_x burners.
4. Flue gas recirculation.
5. Reduced air preheat.
6. Load reduction or reduced combustion intensity.
7. Ammonia injection.

The concentration of SO_x in the flue gas depends on the concentration of sulphur in the fuel. Coal and residual fuel oil can have high concentrations of sulphur; natural gas usually has appreciably less sulphur and wood has essentially none. Flue gas desulphurization (FGD) consists of wet and dry types which produce

TABLE 11-1

A COMPARISON OF EMISSIONS FROM TEEPEE BURNERS AND A WOOD-FIRED THERMAL PLANT

Emission	From Incineration kg/t (dry fuel)	From Thermal Plant kg/t (dry fuel)
Particulates	7.00	0.2
SO_x	0.01	0.01
NO_x	1.00	2.20
CO	13.00	0.06
Non-Methane Hydrocarbons	11.00	0.70
Polynuclear Aromatic Hydrocarbons	1.00	0.02

unmarketable by-products or regenerative types which produce marketable sulphur and sulphuric acid.[42]

Commercial FGD processes are the lime/limestone, double alkali, Wellman-Lord, magnesium oxide, sodium scrubbing and dry scrubbing methods. Lime and limestone, double alkali, sodium scrubbing and dry scrubbing are non-regenerative.[42] In the lime and limestone processes the sulphur dioxide in the flue gas contacts an alkali slurry producing calcium sulphite which is land-filled. The double alkali process consists of flue gas pre-treatment, sulphur dioxide absorption, absorbent regeneration and solid/liquid separation. The Wellman-Lord process uses mainly an aqueous sulphite solution to absorb sulphur dioxide and produce sodium bisulphite which is concentrated; the process is more than 90 percent efficient, but requires 3.6 to 12 percent of the electricity generation for the process. The magnesium oxide process is used primarily for large coal or oil-fired installations. In the magnesium oxide process magnesium sulphite is formed from magnesium oxide and subsequently calcined to regenerate magnesium oxide and produce native sulphur. Sodium scrubbing is common with industrial boilers. In this process sodium hydroxide, or less commonly sodium carbonate reacts with sulphur dioxide. In dry scrubbing, the absorbing liquor is sprayed into the exhaust gas. The reaction products are removed at the bottom of the spray tower or in the particulate control equipment.

There are presently no practical methods for reducing carbon dioxide/carbon monoxide from cogeneration plants. Research is underway in this area, but practical control technology is a long way off.

Trace elements are emitted during combustion of all substances, but they are particularly abundant in emissions from coal or heavy oil plants. However, most harmful trace elements are nonvolatile and the highest concentrations report to the flyash where they can be recovered with the particulates.

Particulate emissions consist of fly ash and organic matter and they are a result of steam turbine or diesel engine generation. The level A particulate emission guideline of 0.10 grains per standard dry cubic foot of combustion products from the furnace (1977 Pollution Control Objectives for the Forest Products Industry) can be met with a new multi-cyclone collector system.[19] Older installations are only required to meet Level B particulate emissions of 0.20 grains per standard dry cubic foot of combustion products. Stack gas cleanup to remove particulates is accomplished at wood burning plants by fabric filters (bag houses) or cyclones.[54] Fabric filters can also be used at coal plants. Electrostatic precipitators are not effective in wood burning plants, but they can be used with coal or oil-fired plants.

Electrostatic precipitators are particularly efficient with large boilers, but they are adaptable to small boilers.[42] Efficiencies of electrostatic precipitators for oil-fired boilers range from 45 to

90 percent and for coal-fired boilers efficiencies can be higher than 99 percent. Electrostatic precipitators are affected by the fuel characteristics such as sulphur content, alkali content and particle size.

Fabric filters are as much as 96 to 99 percent efficient on large coal-fired boilers and they are more cost effective than electrostatic precipitators on low sulphur coals.[42] Unfortunately, fabric filters commonly have high maintenance requirements and they are adversely affected by potentially corrosive substances and oil fly ash.

Multitube cyclones are sometimes used in wood-fired plants.[42] However, they generally have lower particulate removal efficiency than electrostatic precipitators or fabric filters. They are particularly ineffective in removing particles of less than 10 microns diameter.

Wood waste at many sawmill sites is presently landfilled or burned in teepee burners. Landfilling produces leachates and uncontrolled burning in teepee burners produces unsatisfactory particulate emissions. The latter can cause respiratory problems among nearby inhabitants. These environmental problems can be significantly reduced with controlled burning at wood-fired thermal power generation or cogeneration plants.

Air-borne contamination can also arise from storage and disposal areas as well as conveyorways. Wood chips, sawdust, coal dust or ash dust can be contaminants depending on the circumstances. These can be controlled by water spraying or covering the material.

11.3 WATER CONTAMINATION AND FOGGING

A factor affecting the site selection of cogeneration plants is the supply of water which may be required for boiler feed and condenser cooling. Cooling water from a small facility (several megawatts) is usually discharged to a larger body of water (once-through cooling) with the requirement that the temperature rise in the receiving waters beyond the immediate zone of influence would not be greater than 1°C. For large thermal plants there could be a danger of thermal pollution from cooling water discharge. Cooling water from a large facility is usually condensed by means of mechanical or natural draft cooling towers which can produce local fog under adverse weather conditions.

The availability of a fresh water supply for boiler feed could present a problem at some sites and would require a detailed investigation of the present domestic water supply. Boiler feedwater contains corrosion inhibitors to prevent boiler tube fouling and should be treated separately from cooling water.[42]

Liquid waste also includes water from emission control devices. This water could be used for dust abatement which would maintain the water in a closed system.

11.4 FISHERIES

Plant transmission and distribution line construction, cooling water supply, acid rain and waste disposal can have impacts on fish and wildlife. Fishing is an important component of the B.C. economy. Many rivers and streams provide spawning and rearing habitat for anadromous fish. The most common concerns arise from the loss of fisheries habitat because of access road development, the timing of construction activities and acid rain.

The heavy rainfall which occurs along the B.C. coast creates a significant need for managing water runoff and river sedimentation, particularly in those areas potentially affecting streams with high fisheries values. More site specific information would be required during detailed route selection studies to assess the quality of salmon streams, critical habits, and timing constraints. Several guidelines and standards for water crossings and powerline clearing are available for route planning and construction specifications.[73,74] In addition, the provincial Ministry of Environment has produced a set of technical objectives for environmental standards at water crossings.[75]

Acid rain is produced from the reaction of rainwater with NO_x, SO_x and CO_2 in the air. Controlling acid rain requires that these components, particularly NO_x and SO_x be kept to minimum levels.

11.5 WILDLIFE

Changes in wildlife habitat resulting from right-of-way construction and plant location can affect some large mammals and small fur bearers. These effects are usually less important than potential fisheries impacts. It is likely that measures employed to reduce disturbances to salmon streams would also protect the streams for other wildlife uses. Plant siting can be important to winter range and calving areas for large mammals. Warm water discharges into lakes and rivers on migration routes can adversely affect winter migration over water bodies which were historically ice-covered. Changes in wildlife habitat can also affect traplines and hunting territories.

11.6 LAND USE

The amount of land required for a cogeneration plant would be small. However, land use conflicts would increase significantly if a tree farm was required for a fuel supply or if significant transmission or distribution was necessary. The operation of a tree farm to supply wood fuel would require large amounts of dedicated land.[24] Based on a 10-year growing cycle as much as 190 ha would be required to provide fuel for each megawatt of wood-fired thermal generating capacity based on Vancouver Island growth rates for red alder. Depending on the location, land use conflicts could arise with other resource users.

Transmission or distribution systems are an important component of any generating facility. The cost of the systems and their environmental impact are proportional to the length of the transmission or distribution line and its voltage. In many cases, where small, remote generating facilities are being considered, transmission or distribution costs limit project feasibility. Rights-of-way can interfere with timber leases by hampering access to logging areas.

11.7 VISUAL IMPACT

The visual impact of a cogeneration plant is reduced because of the association of the plant with a related industrial site. However, the selection of an appropriate site for a plant is generally dependent on a number of factors, with public acceptance being one of the most important. Powerplants are often thought of as dirty, ugly and noisy facilities. This concern can be minimized through good engineering and architectural design. The visual impact of a transmission or distribution line and right-of-way can affect the value of an area for recreation and tourism by disturbing and pristine nature of the landscape.

11.8 NOISE

Noise is also partly mitigated by locating the cogenerating plant within an industrial site. Noise pollution could be minimized by the use of sound-proofing materials and vent silencers. Fuel handling at the thermal plant site would involve stockpiling and recovery operations. The use of wood requires a logging operation which would be the source of some noise. Hogging could be done in the bush if it is the source of the fuel or alternatively, where there are a number of fuel sources, it is probably more practical to hog the wood at the sawmill or powerplant sites. The choice of haul routes from the fuel source to the powerplant site would require planning to minimize effects on other users of the haul routes as well as on those persons living along the routes. If on tidewater, coal could be transported to the powerplant site by barge, but a suitable off-loading facility would be required.

11.9 SOCIO-ECONOMIC IMPACTS

The activity associated with obtaining and handling the fuel for a thermal plant could have important socio-economic influences. If wood (waste wood or tree farm) is the primary fuel, a significant amount of local labour would be required. This would likely be viewed as a benefit of a wood-fired thermal project.

SECTION 12.0 - ECONOMIC ANALYSIS OF COGENERATION

12.1 INTRODUCTION

Implementation of cogeneration depends on many economic and technologic factors. The economic factors are described in this section. The economic feasibility of cogeneration depends on the difference between the cost of energy from cogeneration and the cost of energy from the utility, based on financial criteria selected by the cogenerator. Economic feasibility is commonly evaluated by comparing paybacks, internal rates of return, net present values and/or unit energy costs. The cost of cogeneration ultimately forms the basis of economic feasibility and consists of the following components:

1. The incremental capital cost for electric generation, substation additions and transmission additions.

2. Additional operation and maintenance costs, including labour, ash disposal, etc.

3. The cost of additional fuel.

Cogeneration can produce energy savings and improved cost effectiveness in the marketplace. In 1984, a survey of B.C. pulp and paper mills identified equipment replacement, process changes and switching to hog fuel as important for energy savings.[23] These same energy saving measures were found to have the shortest pay back periods. Pulp and paper companies have a requirement that the financial benefits of cogeneration must repay all capital costs in 2 to 3 years, net of any grants received. In general, profit sustaining investments which maintain competitiveness in the marketplace, such as new higher output paper machines, tend to have a higher priority for available funds than energy-savings alternatives, particularly if installation of these alternatives requires a temporary shut-down of the mill. These have been serious impediments to otherwise economic projects.

The fuel cost depends on the type of fuel (primarily hog fuel, residual oil, natural gas or coal). As noted in Section 6.0, hog fuel, residual oil and natural gas are the common fuels for steam production in the forest industry. In B.C., hog fuel and residual oil are common on the South Coast and hog fuel and natural gas are common in the Interior. Fuel costs consist of the purchase price, including taxes, the net transport cost, and for hog fuel, the cost of fuel preparation and a disposal credit. Determining the most appropriate cost for fossil fuels is an added complication in estimating the fuel cost. For example, for natural gas, should one use the domestic industrial price, export price or domestic residential price - i.e. opportunity cost?

Operation and maintenance costs for cogeneration systems include electricity cost, labour, the cost of replacement parts and overhead costs. Standby charges for the provision of utility back-up power are a fixed cost of cogeneration. Schedules 1200, 1201, 1210, 1211 and 1821 are applicable to most industrial customers in Zone I. Under these schedules outlined in Tables 12-1 and 12-2, B.C. Hydro charges a fixed charge (demand) as well as an energy charge.

Some government and utility actions have affected the economics and hence the implementation of cogeneration. As of 31 December 1979, industrial cogeneration development in Canada received encouragement with the federal government's decision to allow Class 34 depreciation for cogeneration.[67] Class 34 depreciation permits a 3 year write-off of eligible capital expenditures against taxable income as follows: 25 percent the first year, 50 percent the second year and 25 percent the third year. Eligible capital expenditures include heat recovery equipment designed to conserve energy by extracting and re-using waste heat or the use of fuels derived from waste (e.g. MSW or wood waste).[76] Electric generating plants fired on fossil fuels can qualify if the heat rate is less than 7384 kJ/kW·h of electricity produced.

Utility actions have also affected the spread of cogeneration facilities. Before 1980, mills used cogeneration to reduce large swings in power demand because of B.C. Hydro's demand charge. Post-1980 reductions in the demand charge encouraged some mills to base load their own turbogenerators and use the B.C. Hydro supply for swing purposes.

Technological factors, such as the following, can also affect the implementation of cogeneration by industry:[77]

1. The introduction of thermo-mechanical pulping which reduces steam demand and increases electricity demand.

2. New technology in paper drying such as infrared dryers which reduce steam demand.

3. Parallel operation of cogenerator/utility equipment which requires sophisticated and reliable interconnection equipment to prevent personal injury or equipment damage.

4. Additional pollution control equipment which could be required to retain the same level of emissions with increased steam production.

12.2 CAPITAL COST

The capital investment required for a cogeneration project depends on the amount of additional equipment required. The following scenarios were identified:

1. Replace pressure reducing valves with compatible topping steam turbines exhausting or extracting at process steam pressures while assuming the existing boiler operates at sufficient pressure.

TABLE 12-1

B.C. HYDRO ELECTRIC TARIFF: SCHEDULES 1200, 1201, 1210 AND 1211

GENERAL SERVICE (35 kW and over)

Availability: For all purposes. Supply is 60 hertz, single or three phase at secondary or primary potential. The Authority reserves the right to determine the potential of the service connection.

Applicable in: Rate Zone I.

Rate: Basic Charge $4.09 per month

Demand Charge

First 35 kW of billing demand per month - Nil
Next 115 kW of billing demand per month @ $3.27 per kW
All additional kW of billing demand per month @ $6.28 per kW

plus

Energy Charge

First 275 kW·h per month @ 7.81¢ per kW·h
Next 6725 kW·h per month @ 5.77¢ per kW·h
Next 23000 kW·h per month @ 4.26¢ per kW·h
All additional kW·h per month @ 2.76¢ per kW·h

Discounts

1. A discount of 1 1/2% shall be applied to the above rate if a customer's supply of electricity is metered at a primary potential.
2. A discount of 25¢ per kW of billing demand shall be applied to the above rate if a customer supplies transformation from a primary potential to a secondary potential.
3. If a customer is entitled to both of the above discounts, the discount for metering at a primary potential shall be applied first.

TABLE 12-1 - (Cont'd)

Special Condition: A demand meter will normally be installed. Prior to the installation of such a meter, or if such a meter is not installed, the demand for billing purposes shall be the assessed demand estimated by the Authority.

Special Condition: (Closed) Where electricity is supplied under Schedule 1272 for air conditioning of, or as a principal space heating fuel for the premised being supplied, and, in addition,

1. all metering is at the secondary potential on the load side of the customer's transformers, and
2. the customer provides the necessary transformers and all associated equipment other than meters, and
3. electricity supplied for purposes within Schedule 1272 is metered through a separate single meter, and separately billed on that schedule,

Then all other electricity supplied at the same premises shall be metered through a separate single meter and separately billed on Schedule 1211.

This condition is available only to a customer in those premises with respect to which the Authority, prior to 1 April 1969, agreed that service would be provided under this condition and only with respect to the load which the Authority, prior to 1 April 1969, agreed to provide with service.

TABLE 12-2

B.C. HYDRO ELECTRIC TARIFF: SCHEDULE 1821

GENERAL SERVICE - TRANSMISSION (5000 kW and over)

Availability:	For all purposes. Supply is 60 hertz, three phase at a nominal potential of 60,000 volts or higher as available. Service under this schedule will only be made available where in the Authority's opinion the customer's immediate, or immediate and prospective load is such that service at 60,000 volts or higher is required in order to conform with sound and orderly development of the Authority's electrical system.
Applicable in:	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate:	Demand Charge: $4.097/kV·A of billing demand per month plus Energy Charge: All kW·h/mth at 2.341¢/kW·h.
Billing Demand:	The demand for billing purposes in any month shall be the greatest of: 1. The maximum demand for that month. 2. 75% of the highest maximum demand registered in any one of the immediately preceding 11 months. 3. 5000 kV·A.
Monthly Minimum Charge:	$4.097/kV·A of billing demand.

2. Replace the steam lines and auxiliaries and add a steam turbine to an existing high pressure boiler.

3. Replace the present steam boiler with a high pressure boiler and add suitable steam lines, auxiliaries and a steam turbine; this scenario could occur when an outdated boiler is being replaced.

4. Install a new high pressure steam boiler and related equipment when expanding an existing mill or building a new mill.

In scenarios one and two the capital costs would be charged wholly to electricity generation, whereas, in the third and fourth scenario, only the incremental cost of the high pressure boiler system and steam turbine over the cost of the low pressure boiler system with pressure reducing values would be charged against electricity generation.

Major capital items in a cogeneration plant include all or part of those listed in Table 12-3. The items which are required depend on the necessity for replacement or addition of new equipment based on the state of steam and/or electrical generation facilities at the proposed site.

Major equipment costs must be corrected for installation costs, other direct plant costs and indirect costs by using quotes from suppliers or estimates such as those listed in Table 12-4. Boiler plant capital costs include the boiler, structural steel buildings, foundations, ash handling facilities, mechanical dust collectors, steel stack and breaching, as well as the associated electrical, instrumentation and safety systems.[19] Turbine generator plant capital costs include the turbine generator unit, feedwater heating plant and auxiliaries, structural steel turbine house, transformers and associated electrical, control and safety systems.[19] Turbine costs depend on the turbine type, power output, the number of stages, turbine efficiency and other design parameters. For example, condensing/extraction turbines are more expensive than backpressure turbines.

12.3 FUEL COST

(a) Introduction

The cost of fuel depends on many factors. These factors include the following:

1. Type of fuel (i.e. purchase price).
2. Transportation and unloading.
3. Processing
4. Storage.
5. Heat rate (i.e. amount of fuel required).

TABLE 12-3

MAJOR CAPITAL COST ITEMS FOR A COGENERATION SYSTEM

1. Major Equipment Costs:

    - Fuel Handling and Storage
    - Boiler
    - Turbine Generator or Engine
    - Pollution Control
    - Major Electrical Equipment - Switch Gear, Transformers

2. Major Equipment Installation Costs:

    - Installation Labour
    - Structural Supports, Insulation and Paint

3. Other Direct Plant Costs:

    - Instrumentation and Controls
    - Piping
    - Ancillary Electrical Equipment
    - Buildings
    - Yard Improvements
    - Service Facilities
    - Land

4. Indirect Costs:

    - Engineering and Supervision
    - Construction Camp and Expenses
    - Contractor's Fee
    - Insurance
    - Interest During Construction
    - Corporate Overhead
    - Contingency

TABLE 12-4

EQUIPMENT COST ADJUSTMENT FACTORS

Installed Equipment Cost	1.4 - 1.5
Other Direct Plant Costs	2.2 - 3.0
Indirect Plant Costs	1.25 - 1.40

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*1 Use the major equipment cost as the base cost for estimating the installed equipment cost and other direct plant costs and the total direct cost, i.e. the sum of the installed equipment cost and other direct plant costs as the base cost for estimating the indirect plant costs. These adjustments produce an estimate of total investment cost. Interest during construction and corporate overhead have not been included.

The purchase price of various fuels and their heating values are summarized in Table 12-5. The cost of residual oil is the highest of the four fuels and hog fuel is the most economical. Hog fuel, natural gas and residual oils are the fuels used for cogeneration by the B.C. forest industry, which provides most of the cogeneration in the province.

Transportation methods vary with the fuel and the location. Hog fuel is moved by barge on the Coast and by truck in the Interior. Logs can be moved by log barge or log boom on the coast and by truck inland. Natural gas is transported by pipeline which restricts its use to mills near the main pipeline routes. Residual oil is moved by ship or tanker truck.

Processing applies only to hog fuel; natural gas and residual oil are processed prior to purchase. Hog fuel processing requires acquisition of bark from the debarking of saw and pulp logs followed by shearing, chipping or hogging and drying.

Storage is necessary for residual oil and hog fuel, but not for natural gas. Residual oil is simply stored in special tanks and hog fuel is stored in open piles.

The heat rate varies significantly with the fuel. Heat is required to evaporate the moisture in hog fuel and this increases the heat rate. The moisture content of hog fuel typically ranges from 50 to 65 percent. New high efficiency hog fuel boilers have efficiencies of 85 percent compared to 70 percent from older boilers and this development could appreciably reduce the plant fuel cost.

(b) Wood Waste

Recovery of wood waste depends on the source. Bark, planer shavings, sawdust and ends can be recovered from sawmills, whereas whole logs and branches are recovered from the forest. Sawmill refuse requires a loader and a truck for transportation, but recovery of forest refuse may require a yarder as well.

The average cost of yarding by region for the coast of B.C. is summarized in Table 12-6.[25] The estimate assumes an average piece size of 1.1 m^3 and is based on the cost of yarding as a percentage of the total cost of logging for each region. As expected, costs are lowest on the South Coast Mainland and highest on the Queen Charlotte Islands.

The cost of yarding is influenced, not only by location, but also by piece size. The relationship of yarding cost to piece size for the two extremes, the South Coast Mainland and Queen Charlotte Islands, is illustrated in Figure 12-1.[25] The normal logging costs are designated by the letter "a". The cost of medium residue utilization ("m") does not significantly increase the yarding cost. However, high residue utilization ("h") would have a significant impact on yarding cost.

TABLE 12-5

FUEL COSTS (1988$)[*1]

Fuel	Fuel Cost	Heating Value
Coal	$20.00/t[*2]	
	1.30/GJ	25.75 MJ/kg[*3]
Natural Gas	0.0675/m^3	
	1.80/GJ	37.51 GJ/$10^3 m^3$
Residual Oil	0.23/L[*4]	41.75 MJ/L
	5.50/GJ	43.76 GJ/t
Wood Waste	1.20t(BD) Interior	19.75 MJ/kg(BD)
	0.06/GJ	
	11.70/t(BD) Coast	21.00 MJ/kg(BD)
	0.56/GJ	

[*1] References: 19, 25, 26

[*2] f.o.b. mine.

[*3] Coal quality varies considerably with rank and ash content. This heating value is typical of as received East Kootenay thermal coals.

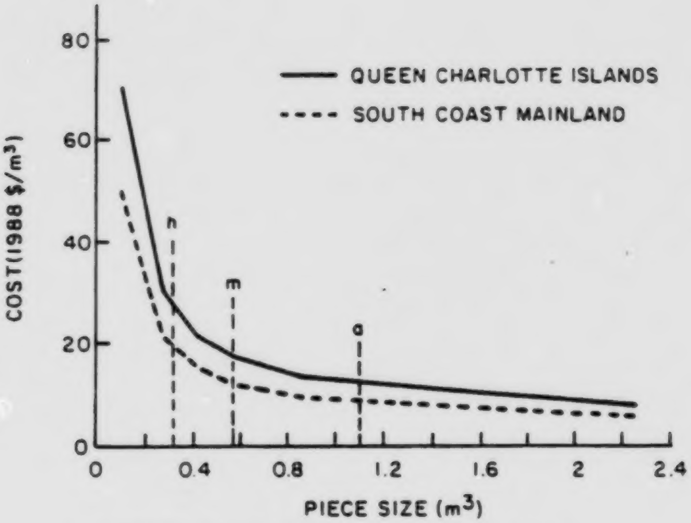
[*4] Delivered cost.

TABLE 12-6

ESTIMATED INCREMENTAL YARDING COST BY B.C. COASTAL REGION ($\$/m^3$)[*1]

	Queen Charlotte Islands	North Coast Mainland	Mid-Coast Mainland	South Coast Mainland	East Vancouver Island	West Vancouver Island
Logging Activity Cost ($\$/m^3$)	41.10	40.75	38.75	33.10	35.90	35.20
Yarding Cost Share (%)	19.9	20.0	21.1	23.4	22.5	23.2
Yarding Share Camp Cost ($\$/m^3$)	3.86	2.72	2.86	0.80	1.36	1.40
Yarding Cost ($\$/m^3$)	12.04	10.90	11.04	8.55	9.44	9.57

[*1] $1988 Can. inflated from $1986 Can.



h - AVERAGE INCREMENTAL PIECE SIZE FOR HIGH RESIDUE UTILIZATION

m - AVERAGE PIECE SIZE FOR MEDIUM RESIDUE UTILIZATION

a - AVERAGE PIECE SIZE NORMAL LOGGING, B.C. COAST

Figure 12 - 1

RELATIONSHIP OF YARDING COST TO PIECE SIZE IN THE QUEEN CHARLOTTE ISLANDS

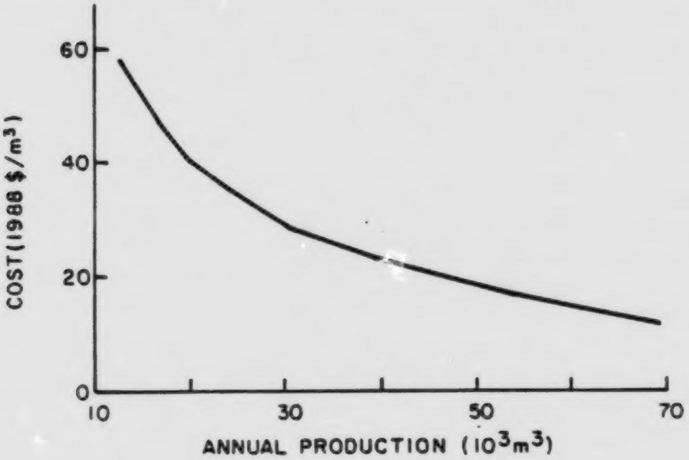


Figure 12 - 2

RELATIONSHIP OF CHIPPING COST TO MACHINE UTILIZATION

The cost of chipping depends on machine utilization (Figure 12-2).[25] The cost estimates assume long, straight pieces. Chipping costs commonly range from \$11.00 to \$13.15/m^3 for yard chippers and generally costs are more than \$26/m^3 for mobile chippers. The cost differential is caused by the difference in annual production which is in turn caused by the following:

1. The added moving and set-up costs of the mobile chippers.
2. The differing ability to feed the machine at each landing because of a lack of space and available refuse.
3. The higher capital cost for mobile chippers per unit of production.
4. The smaller size and the effect of economies of scale on operating costs (inability to handle large pieces and higher per unit labour cost).

The economics of utilizing wood waste or hog fuel as a fuel for thermal generation of electricity is highly dependent on the cost of delivering wood fuel of suitable quality to the generating station. The cost of hauling wood waste depends on the method of transport, distance and the quantity of solid wood (m^3) per load. The sum of owning and operating costs for off-highway trucks, containers with sheared wood and chip vans with chips or hog fuel are illustrated in Figure 12-3.[25] The cost of hauling wood waste increases with increasing distance and decreasing load size. Duals off-highway truck are the most economical and chip vans are the least economical.

The cost of hauling forest refuse consisting mostly of solid logs is illustrated in Figure 12-4.[25,41] The forest refuse is hauled in an open-ended box.

The total owning and operating costs for marine transportation of wood waste in log booms, log barges and chip scows are illustrated in Figure 12-5.[25] As with land transportation, the cost of hauling wood waste by sea increases with increasing distance and decreasing load size. Log booms are the most economical, but they are only suitable for large pieces of wood waste. Losses are high with log booms and the cost of handling normal logs is increased. Chip barges and log barges are advantageous because they can handle any size of wood waste.

The recent cost of hog fuel has been approximately \$10 per volumetric unit (\$4.80/m^3).[25] However, in 1985 hog fuel sold for as low as \$3.50 per volumetric unit (\$1.70/m^3). During short-run imbalances, such as the construction of approaches to the Alex Fraser Bridge, costs can rise to \$20 per volumetric unit (\$9.65/m^3).

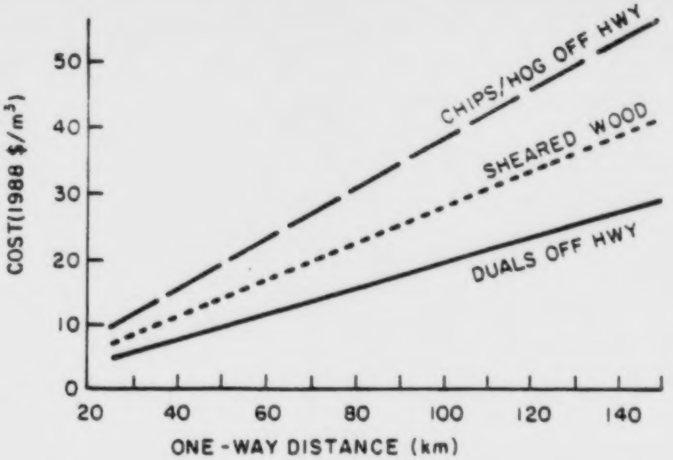


Figure 12-3

TOTAL OWNING AND OPERATING COSTS OF LAND TRANSPORTATION SYSTEMS FOR WOOD WASTE

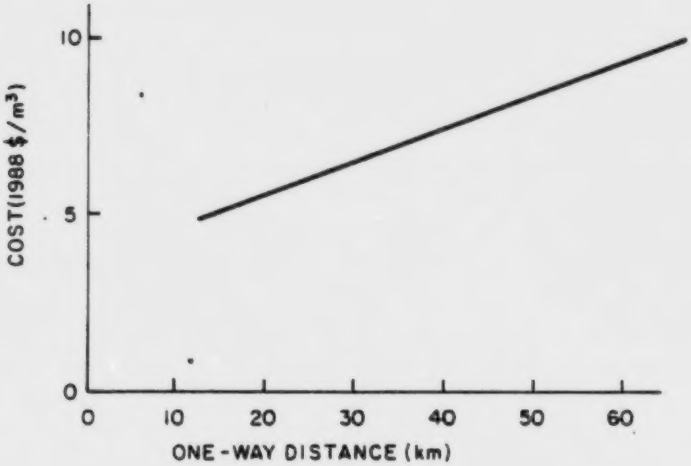


Figure 12-4

TOTAL OWNING AND OPERATING COSTS OF TRUCK TRANSPORTATION FOR FOREST REFUSE

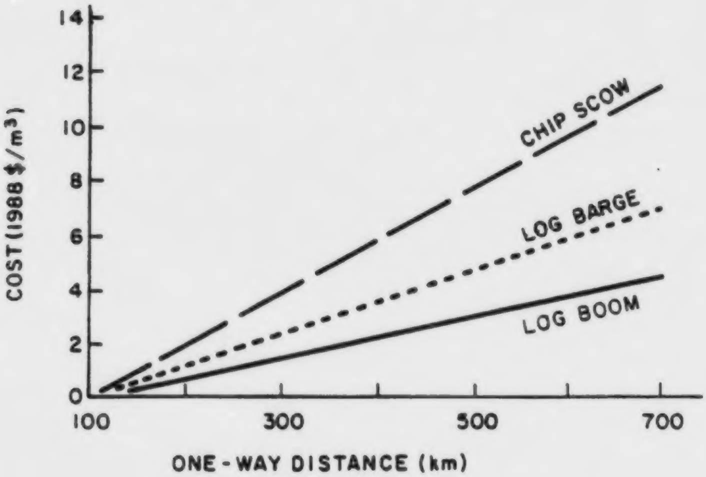


Figure 12-5

TOTAL OWNING AND OPERATING COSTS OF MARINE TRANSPORTATION SYSTEMS FOR WOOD WASTE

(c) Fuel Cost Scenarios

In this report, four fuels were considered for cogeneration: wood waste, natural gas, residual oil and coal. The delivered cost of natural gas was assumed to be \$67.50/$10^3\mathrm{m}^3$ or $1.80/GJ (1988 dollars) and this cost was assumed to rise at the rate of inflation, i.e. 5 percent/annum (Table 12-5). It is recognized that increases in the cost of natural gas will probably be stepped, but it is expected that the increases will approximate a 5 percent average annual increase. Similarly, the delivered cost of residual oil was assumed to be $0.23/L or $5.50/GJ and its cost was assumed to rise in a stepped manner, but the average increase would be 5 percent/annum, equivalent to the rate of inflation. The cost of coal was assumed to be $20/t (FOB mine) and based on an as-received heating value of 25.75 MJ/kg. The transportation cost would vary significantly with the location of the cogenerator. However, coal was considered for comparison only, it is not used at present by any cogenerator in B.C.

Unlike the fossil fuels described above, wood waste is used widely in B.C. and wood waste is transported over considerable distance to some cogeneration plants. For this reason, several fuel cost scenarios were considered for wood waste cogeneration. The fuels for Interior and Coastal cogeneration plants could be quite different. Therefore, they are considered separately.

The costs of hog fuel for a Coastal cogeneration plant are summarized in Table 12-7. It is assumed that the wood waste is either from a self-owned source or acquired through purchase and wood waste from either source requires chipping or hogging. Self-owned wood waste could come from a sawmill adjacent to the pulp mill or require transportation either from the bush or, if purchased, from sawmills assumed to be as far as 20 km away. The costs were corrected for the relative efficiencies of the fuels and boiler in order to estimate the cost of steam. The cost of barge transport (approximately $0.05/GJ for 150 km one-way) was not considered in these estimates.

The cost of steam for a boiler at an Interior pulp mill was estimated in a similar manner. The corresponding costs are summarized in Table 12-8. The relationship of the fuel component of the steam cost to the delivered cost of hog fuel is illustrated for Coastal and Interior mills in Figure 12-6. The plot for wood fuel without supplementary fuel crosses the wood/natural gas line at $1.40/BDt and the wood/residual oil line at $2.50/BDt, the values above which wood fuel is uneconomic.

TABLE 12-7

COST OF FUEL AND THE FUEL COST COMPONENT OF THE STEAM COST FOR A COASTAL B.C. COGENERATION PLANT ($/GJ)

	Self-Owned	Purchase
Cost of Wood	Nil	0.56[*1]
Chipping or Hogging[*2]	0.89(Y), 1.90(B)	0.89(Y)[*3]
Transportation	Nil(Y), 0.72(B)	0.24(Y)[*4]
Disposal Credit[*5]	0.31	0.31
Subtotal	0.58(Y), 2.31(B)	1.38(Y)

Correcting for the relative efficiencies and the use of 10 percent residual oil, the total fuel cost components of the steam cost are as follows:[*6]

	1.41(Y), 3.81(B)	2.45(Y)

[*1] \$11.70/BDt ÷ 21.00 GJ/BDt.

(Y) is an abbreviation for hogging done at a plant yard and (B) is an abbreviation for hogging in the bush.

[*3] Purchase of hog fuel, hogged in the bush, was not considered because the cost was too high.

[*4] Assuming a 20 km one-way haul from a sawmill at a cost of \$5/m^3.

[*5] Equivalent to \$7.50/ODt.

[*6] Boiler efficiency is assumed to be 90 percent with oil and 65 percent with hog fuel.

TABLE 12-8

COST OF FUEL AND FUEL COST COMPONENT OF THE STEAM COST FOR AN INTERIOR B.C. COGENERATION PLANT ($/GJ)

	Self-Owned	Purchase
Cost of Wood	Nil	0.06[*1]
Chipping or Hogging	1.03(Y), 2.27(B)	1.03(Y)[*3]
Transportation	Nil(Y), 0.81(B)	0.27(Y)[*4]
Disposal Credit[*5]	0.32	0.32
Subtotal	0.71(Y), 2.76(B)	1.04(Y)

Correcting for the relative efficiencies and the use of 15 percent natural gas, the total fuel cost components of the steam cost are as follows:[*6]

	1.25(Y), 3.93(B)	1.68(Y)

[*1] $1.20/BDt ÷ 19.75 GJ/BDt.

(Y) is an abbreviation for hogging done at a plant yard and (B) is an abbreviation for hogging in the bush.

[*3] Purchase of hog fuel, hogged in the bush, was not considered because the cost was too high.

[*4] Assuming a 20 km one-way haul from a sawmill at a cost of $\$5/\text{m}^3$.

[*5] Equivalent to $7.50/ODt.

[*6] Boiler efficiency is assumed to be 85 percent with natural gas and 65 percent with hog fuel.

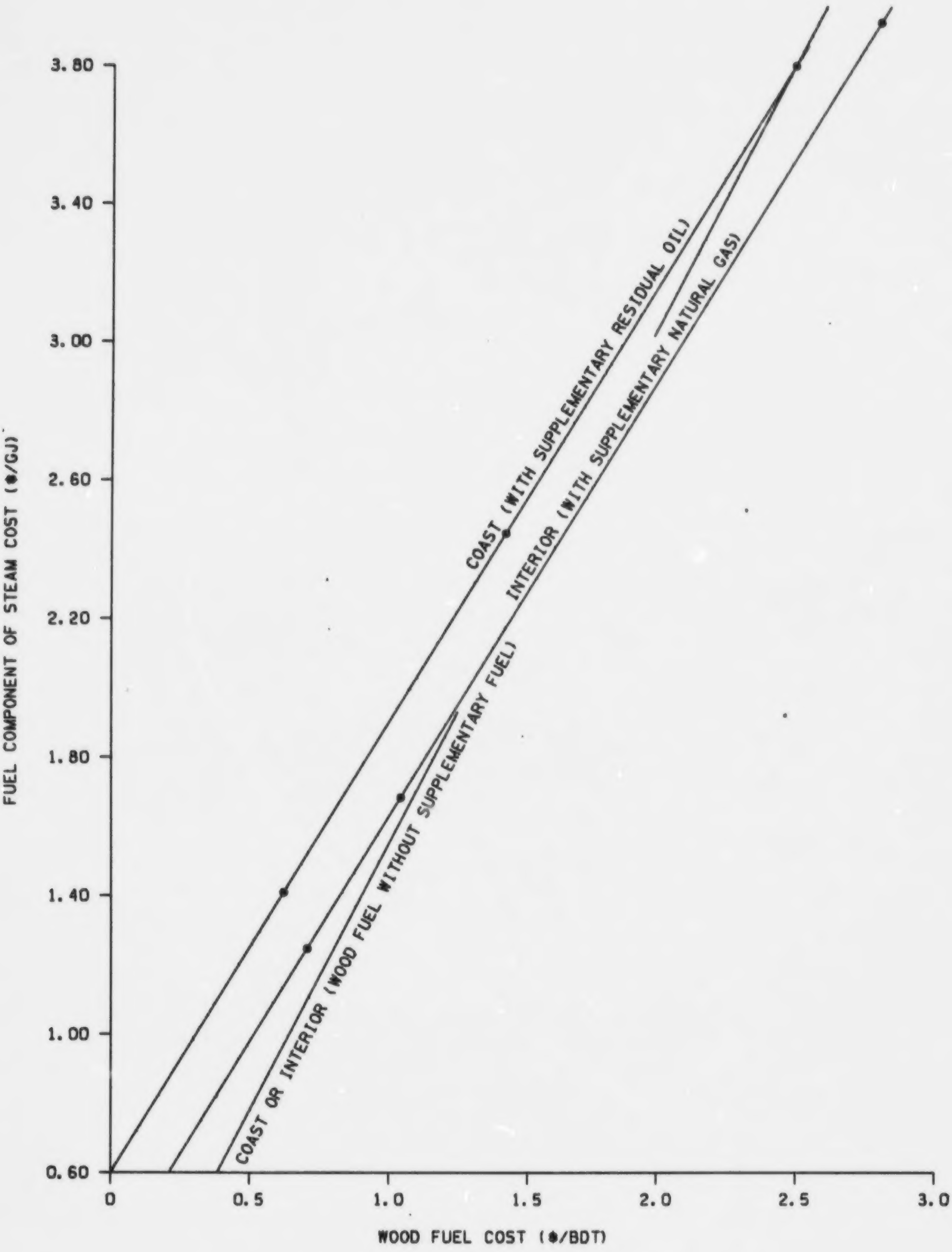


Figure 12 - 6

RELATIONSHIP OF WOOD FUEL COST TO THE FUEL COMPONENT OF THE STEAM COST

12.4 OPERATING COSTS

The operating costs attributable to electricity generation in a cogeneration plant are as follows:

1. Wages for added operating personnel.
2. Additional fuel cost.
3. Added maintenance and repair costs because of the higher throughput of fuel, higher steam pressures and/or additional equipment.

The fuel cost component was described in Section 12.3. For this report the operating cost is exclusive of the fuel cost and was estimated by one of two methods. For cogeneration at pulp mills the operating cost was divided into fixed and variable components. Based on B.C. Hydro standard values for thermal plants, the fixed component was estimated to be 4.1 percent of the capital cost applicable to electric generation and the variable component was 0.131 mills/kW·h of incremental electric generation. The second method was applied to other cogeneration opportunities and assumed a fixed operating cost as a percentage of the total capital cost; an allowance for process steam credit followed. The fixed operating cost percentage varied with the method of steam (or hot water) production according to the value used in the report which is cited.

12.5 ECONOMIC ANALYSIS OF COGENERATION AT PULP MILLS

(a) Introduction

The economic analysis concentrated on the economic conditions for kraft pulp and paper mills in British Columbia for three reasons:

1. Pulp and paper mills have the largest electricity and process steam demands on the B.C. Hydro system.
2. Many of these mills have been converted to use waste wood as a fuel source to provide cogeneration.
3. There are still several mills that could be converted to cogeneration.

Three approaches were taken in the economic analysis of cogeneration in British Columbia:

1. Payback period.
2. After tax internal rate of return.
3. Unit energy (electricity) cost.

These approaches assume that most of the costs are paid by the process steam demand and only the incremental costs directly applicable to electric generation are included in the cost estimates for cogeneration at pulp mills.

For estimating simple payback and internal rate of return the following criteria were used:

1. The construction period was assumed to be one year, so no interest during construction was charged; this oversimplification reduces the capital cost of the facilities, but the effect is not significant because of the generally short construction period.
2. The steam price, annual cost and value of electricity were assumed to inflate at 5 percent per annum over the 25-year projected life of the project.
3. The tax rate was assumed to be 46 percent for each estimate.

(b) Base Case for Pulp Mills

In order to examine the impact of adding electric generation at a kraft pulp mill three base case boiler conditions were assumed: 4240 kPa/400°C (600 psig/750°F), 6310 kPa/445°C (900 psig/835°F) and 8720 kPa/480°C (1250 psig/900°F). For each condition there were mechanical drive turbines and pressure reducing valves (PRV) which reduced the steam pressure to 445 kPa and 1135 kPa (50 psig and 150 psig) for supplying the process. When steam is reduced in pressure by expanding through a mechanical drive turbine or pressure reducing valve the resulting steam has excessive superheat and must be desuperheated by introducing an appropriate amount of boiler feedwater before going to the process. Before the 445 kPa (50 psig) process steam flow is taken off, a line supplies hot water to the feedwater heater. The desuperheater flows are based on estimates from Table 7-8.[19] It is further assumed that 30 percent of the water is lost to the process and must be made up and that there are no other losses.

The mass balance for 4240 kPa/400°C, 6310 kPa/445°C and 8720 kPa/480°C boiler conditions are illustrated in Figures 12-7 to 12-9.

In addition to a mass balance, the enthalpies are also assumed to balance. For example, the enthalpy of steam at 4240 kPa/400°C can be obtained from the typical values in the Mollier Diagram (Figure 8-9). Steam output from the boiler has an enthalpy of 1378 Btu/lb (3205 kJ/kg) compared with a feedwater enthalpy of 330 Btu/lb (768 kJ/kg). Therefore, the enthalpy change in the boiler is 3205 kJ/kg-768 kJ/kg = 2437 kJ/kg or 2.437 GJ/t.

As noted the efficiency of a wood-fired boiler is 65 percent, but this must be modified because of the effect of supplementary natural gas (at 85 percent boiler efficiency) or residual oil (at 90 percent boiler efficiency). Therefore, based on these

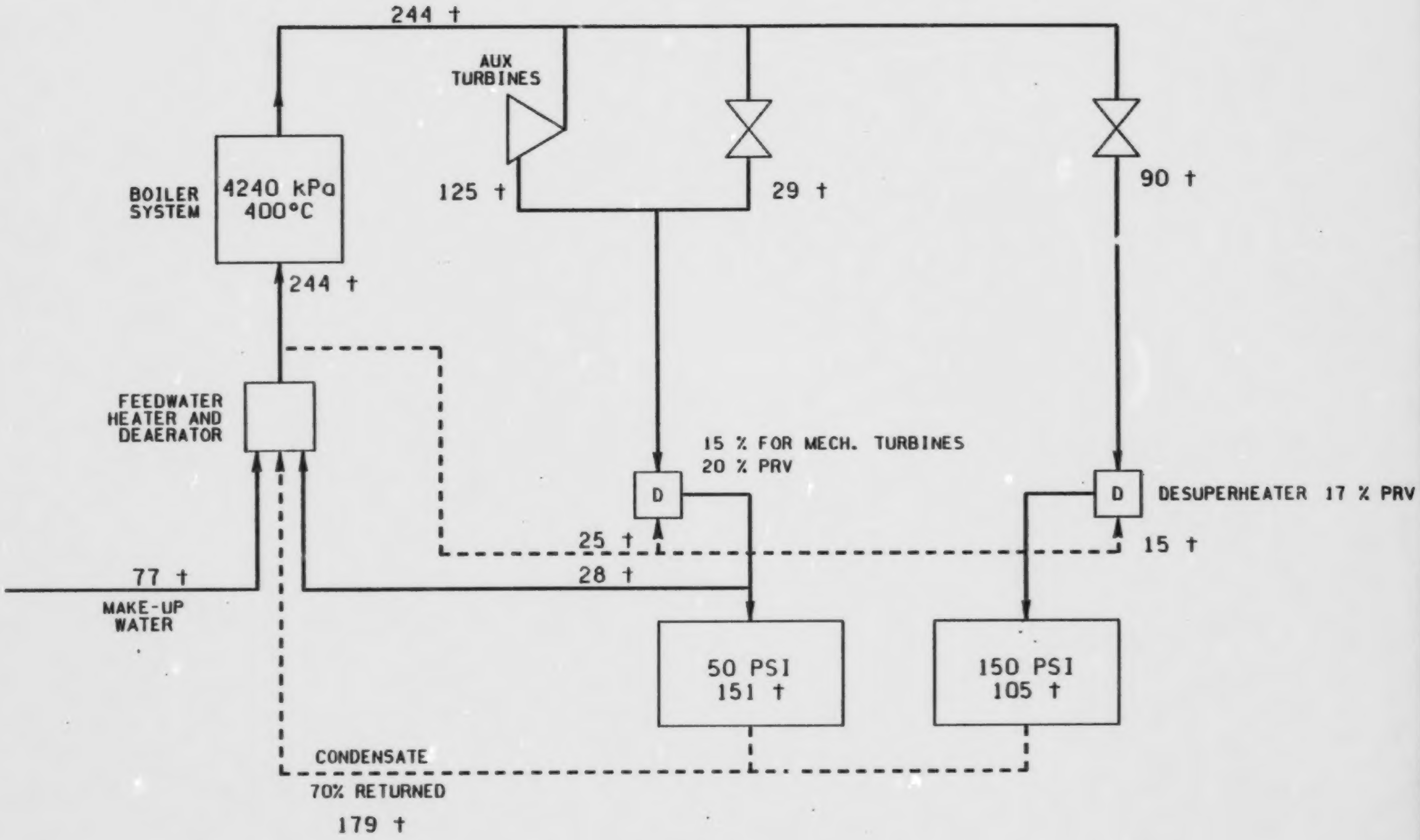

244 t
AUX TURBINES
BOILER SYSTEM
4240 kPa 400°C
125 t
29 t
90 t
244 t
FEEDWATER HEATER AND DEAERATOR
15 % FOR MECH. TURBINES
20 % PRV
D
D
DESUPERHEATER 17 % PRV
25 t
15 t
77 t
28 t
MAKE-UP WATER
50 PSI 151 t
150 PSI 105 t
CONDENSATE
70% RETURNED
179 t

Figure 12 - 7

PULP MILL 4240 kPa PROCESS STEAM SYSTEM (BASE CASE)

- STEAM FLOW IN TONNES/HOUR

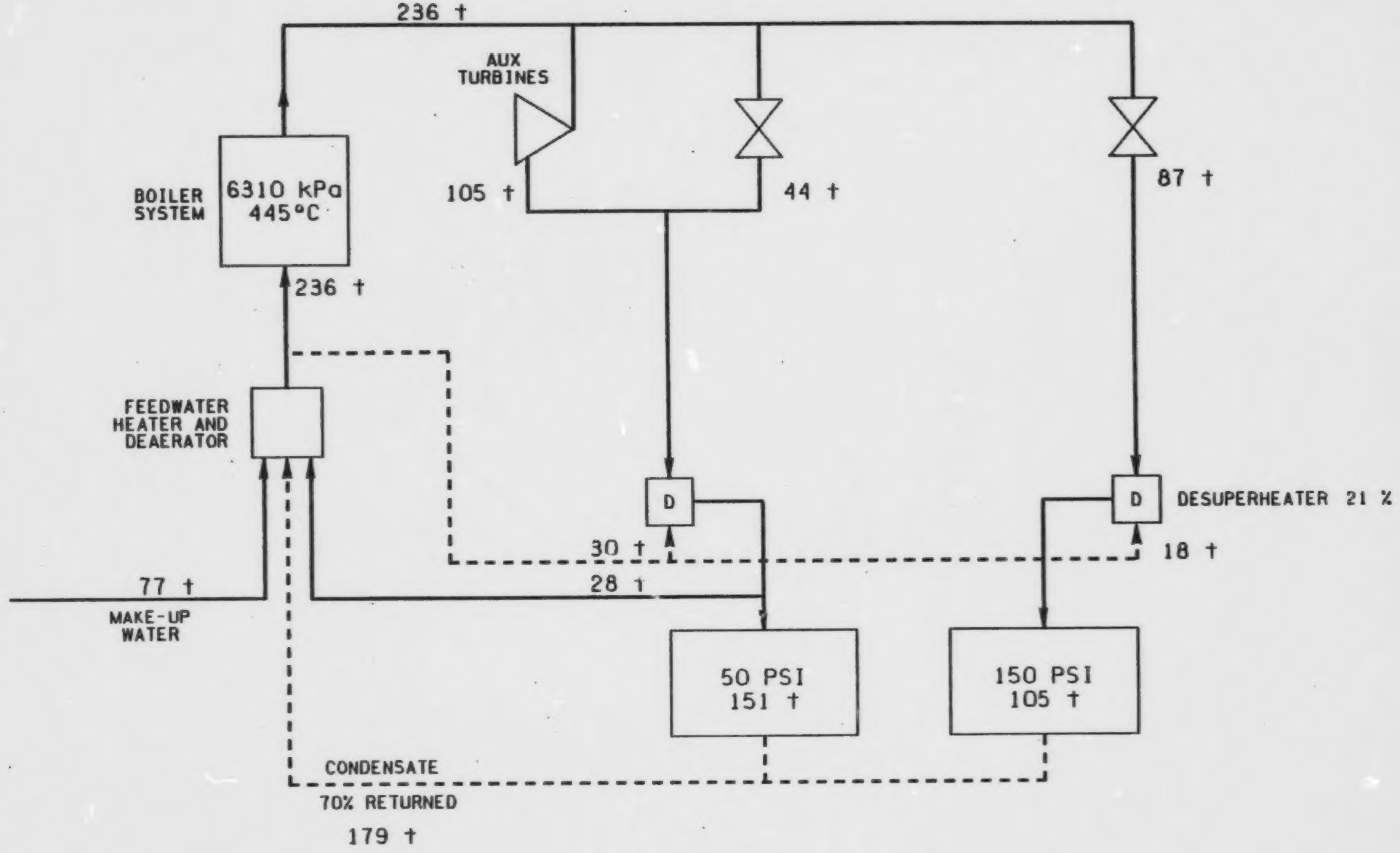

236 t
AUX TURBINES
105 t
44 t
87 t
BOILER SYSTEM
6310 kPa 445°C
236 t
FEEDWATER HEATER AND DEAERATOR
D
D
DESUPERHEATER 21 %
30 t
18 t
77 t
28 t
MAKE-UP WATER
50 PSI 151 t
150 PSI 105 t
CONDENSATE
70% RETURNED
179 t

Figure 12 - 8

PULP MILL 6310 kPa PROCESS STEAM SYSTEM (BASE CASE)

- STEAM FLOW IN TONNES/HOUR

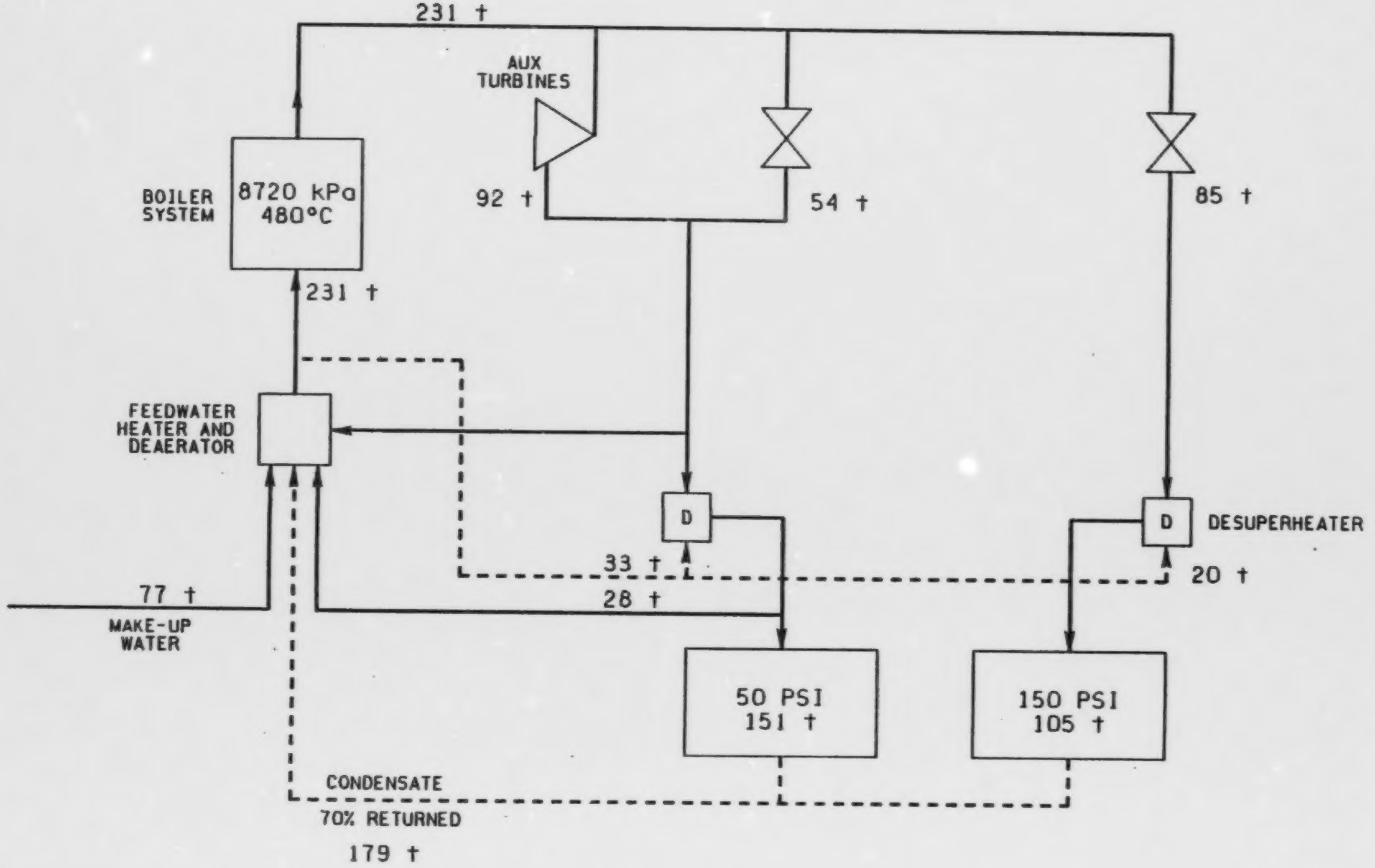

231 t
AUX TURBINES
BOILER SYSTEM
8720 kPa 480°C
92 t
54 t
85 t
231 t
FEEDWATER HEATER AND DEAERATOR
D
D
DESUPERHEATER
33 t
20 t
77 t
28 t
MAKE-UP WATER
50 PSI 151 t
150 PSI 105 t
CONDENSATE
70% RETURNED
179 t

Figure 12 - 9

PULP MILL 8720 kPa PROCESS STEAM SYSTEM (BASE CASE)

- STEAM FLOW IN TONNES/HOUR

assumptions, the fuel energy (assuming natural gas as the supplementary fuel) required to produce 244 t/h of steam is

$$\frac{(2.437\text{GJ/t})(244\text{t/h})}{((.65)(.85)+(.85)(.15))} = 874{,}453 \text{ GJ/h}$$

The energy content of a bone dry tonne (BDt) of Interior B.C. wood waste is approximately 19.75 GJ and the energy content of natural gas is 37.51 GJ/10^3m^3 (Table 12-5). Therefore, approximately 743 GJ/h of wood waste and 131 GJ/h of natural gas would be required. This is equivalent to approximately 38 BDt/h of hog fuel and 3492 m^3/h of natural gas.

Similarly, the heat requirements for a hog fuel/oil-fired boiler for the B.C. Coast would be 880,930 GJ/h. The energy content of bone dry Coastal B.C. wood waste is approximately 21.00 GJ/BDt and the energy content of residual oil is 41.75 MJ/L. Therefore, heat requirements would be approximately 793 GJ/h from wood waste and 88 GJ/h from residual oil. This is equivalent to 38 BDt/h of hog fuel and 2108 L/h of residual oil.

(c) Electric Generation Cost at Pulp Mills

In evaluating electric generation at pulp mills sensitivity analyses were conducted by changing six variables:

1. Removal of pressure reducing valves (PRVs) only or PRVs and some mechanical drives.
2. Boiler pressure.
3. Capital cost.
4. Fuel cost.
5. Fuel mix.
6. Value of electricity.

Boiler pressure and capital cost are interdependent. Increasing the boiler pressure increases the capital cost. The incremental capital cost assigned to electric generation for 6310 kPa and 8720 kPa boiler pressures are estimated to be 6 percent and 15 percent respectively above the cost of systems with 4240 kPa boiler pressure. The capital cost also varies from mill to mill depending on the plant modifications or additions required. Four capital costs were examined based on $465/kW, $680/kW, $910/kW and $1365/kW at 4240 kPa and assuming replacement of pressure reducing valves and other necessary equipment, but excluding replacement of mechanical drive turbines.

The fuel cost and value of electricity are independent of each other, but fuel mix and fuel cost are interdependent. However, the fuel cost per kW·h decreases because of higher efficiencies at higher boiler pressures. The value of electricity is completely independent of the other variables because it depends only on the cost of alternative generation.

The capital costs and electric generation for the two kraft pulp mill scenarios (Coastal and Interior) are summarized in Table 12-9. The capital costs increase with the extent of plant additions and modifications which could include boiler pressure increases and increases in turbine/generator size. The capital costs were estimated to increase 7 to 8 percent as the pressure/temperature of the steam increase from 4240 kPa/400°C to 6310 kPa/440°C.[19] Similar cost increases were assumed for pressure/temperature increases from 6310 kPa/445°C to 8720 kPa/480°C.

(d) Scenario 1 - Replacement of Pressure Reducing Valves

In the first scenario, pressure reducing valves (PRVs) were replaced and in the second both PRV's and mechanical drive turbines were replaced. These changes reduced the requirement for desuperheat as summarized in Table 7-8. As the amount of water to the desuperheater is decreased the amount of steam from the boiler must increase to maintain the same flow to the process. Therefore, both increased steam flow from the boiler and increased fuel flow to the boiler are required. As the quantity of steam is increased, the size of the turbine/generator is assumed to increase in 5 MW increments to maximize electricity production. The turbine outlet pressure also affects the amount of electricity that can be generated as summarized in Table 8-3. As the inlet pressure increases the steamflow required to produce a kilowatt of electricity decreases for a given outlet pressure. However, the rate of change of the steam rate decreases with increasing inlet conditions because of higher losses at higher pressures.

By comparing Figures 12-7 and 12-10 it is apparent that the average hourly boiler steamflow at 4250 kPa/400°C must increase from 244 t/h to 265 t/h to maintain the same steamflow to the process after adding a 15 MW turbine/generator and removing the PRVs. Therefore, the average electricity generated hourly would be

$$\frac{105\ \text{t/h}}{15.9\ \text{kg/kW·h}} = 6\ 604\ \text{kW·h}$$

$$\frac{35\ \text{t/h}}{10.0\ \text{kg/kW·h}} = 3\ 500\ \text{kW·h}$$

$$\text{Total} \quad \overline{10\ 104\ \text{kW·h}}$$

Assuming the plant operates 350 days/annum and 24 hours/day, the annual generation would be 84.87 GW·h. Therefore, the capacity factor would be

$$\frac{(84.87\ \text{GW·h/a})(100)}{(15\ \text{MW})(8760\ \text{h/a})} = 64.6\%$$

TABLE 12-9

CAPITAL COSTS AND ELECTRICITY GENERATION FOR COGENERATION AT PULP MILLS

	Scenario 1			Scenario 2		
	Capital Cost (k$)	Generating Capacity (MW)	Electricity Generation (GW·h)	Capital Cost (k$)	Generating Capacity (MW)	Electricity Generation (GW·h)
4240 kPa/400°C	6 955	15	84.87	10 122	20	146.19
	10 739	15	84.87	15 167	20	146.19
	14 319	15	84.87	19 940	20	146.19
	21 477	15	84.87	29 485	20	146.19
6310 kPa/445°C	9 829	20	127.90	12 516	25	190.90
	15 187	20	127.90	18 834	25	190.90
	20 236	20	127.90	24 789	25	190.90
	30 355	20	127.90	36 720	25	190.90
8720 kPa/480°C	13 214	25	165.87	17 335	30	230.30
	20 416	25	165.87	26 055	30	230.30
	27 205	25	165.87	34 272	30	230.30
	40 807	25	165.87	50 738	30	230.30

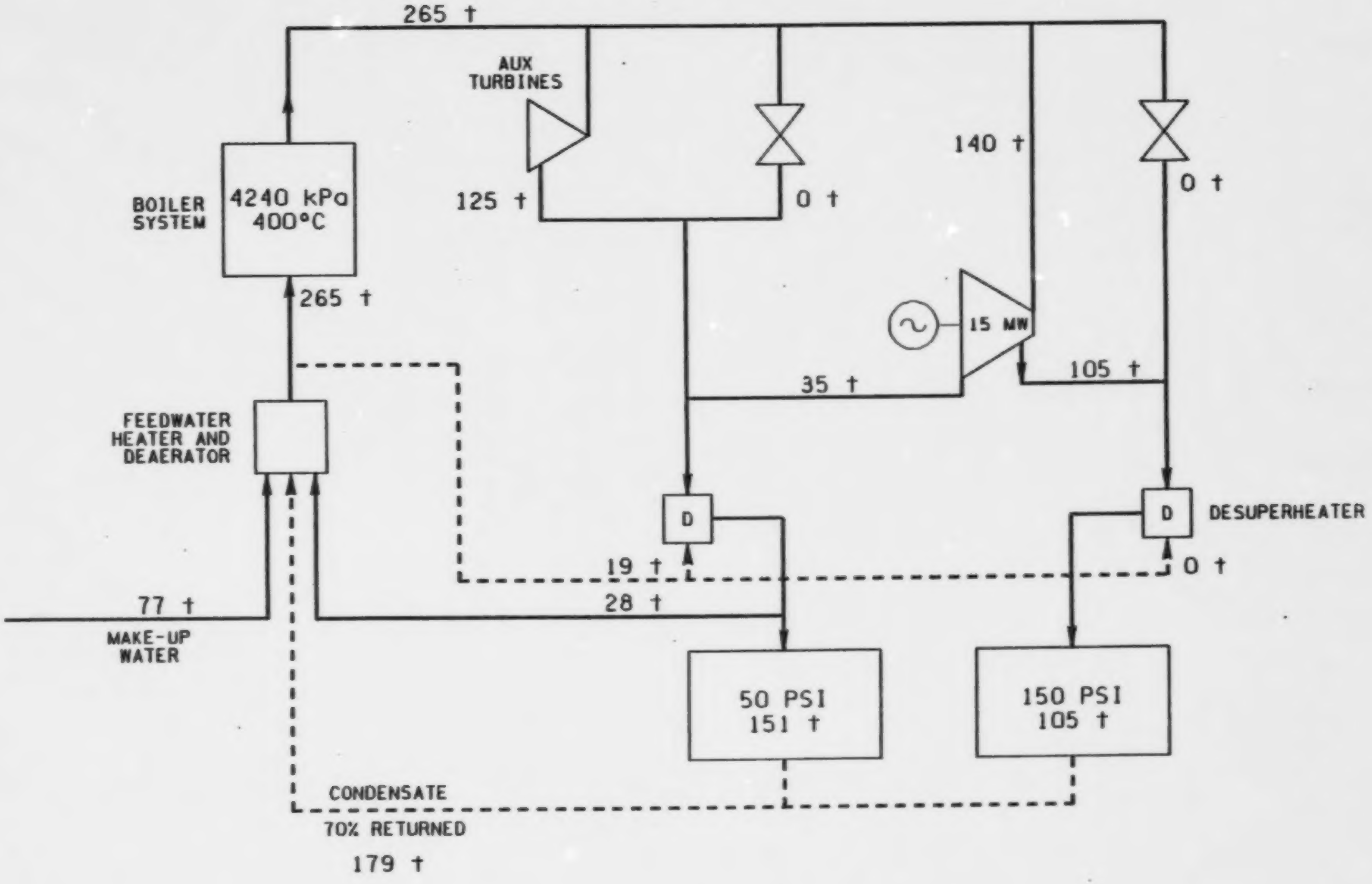

265 t
AUX TURBINES
BOILER SYSTEM
4240 kPa 400°C
125 t
0 t
140 t
0 t
265 t
15 MW
35 t
105 t
FEEDWATER HEATER AND DEAERATOR
D
D
DESUPERHEATER
19 t
0 t
77 t
28 t
MAKE-UP WATER
50 PSI 151 t
150 PSI 105 t
CONDENSATE
70% RETURNED
179 t

Figure 12 - 10

PULP MILL 4240 kPa STEAM SYSTEM WITH 15 MW STEAM TURBINE ADDED (SCENARIO 1)

- STEAM FLOW IN TONNES/HOUR

The incremental boiler steam flow is estimated to be 21 t/h at 3205 kJ/kg (i.e. 67.3 GJ/h) to generate 10.104 MW·h. The heating value of the boiler feedwater is assumed to be 768 kJ/kg. Therefore, the additional fuel energy is

$$\frac{(3205\ \mathrm{kJ/kg}\ 768\ \mathrm{kJ/kg})(1000\ \mathrm{kg/t})(21\ \mathrm{t/h})}{(.65)(.85) + (.85)(.15)} = 75.26\ \mathrm{GJ/h}$$

in the form of steam, corrected for the weighted efficiencies with hog fuel and natural gas firing.

The heat rates for cogeneration in these scenarios are summarized in Table 12-10. The additional heat could be derived from hog fuel, hog fuel/natural gas or hog fuel/oil. The heat rates are generally less than 7384 kJ/kW·h and we will assume for purposes of this study all heat rates are below this benchmark. Therefore, Class 34 depreciation is available for all scenarios as explained in Section 12.1.

If the energy content of bone dry Interior wood waste is 19.75 GJ and the energy content of natural gas is 37.51 GJ/$10^3 m^3$ (Table 12-5), approximately 64 GJ of heat would be supplied by the wood waste and 11 GJ would be supplied by the natural gas. Therefore, the incremental fuel requirements would be approximately 290 m^3/h of natural gas and 3.24 BDt of wood waste per hour. If the boiler operates at full load 24 hours per day and 350 days per annum, the annual incremental fuel requirements would be 27 216 BDt of wood waste and 2 461 000 m^3 of natural gas.

Similar estimates were prepared for boilers at 6310 kPa/445°C and 8720 kPa/480°C for Coastal pulp mills which use residual oil as a supplementary fuel (Figures 12-11 and 12-12) and for pulp mills using hog fuel only. If the additional fuel energy to produce the supplementary steam for electric generation is supplied only by hog fuel, the energy requirement would be

$$\frac{(3205\ \mathrm{kJ/kg}\ 768\ \mathrm{kJ/kg})(1000\ \mathrm{kg/t})(21\ \mathrm{t/h})}{.65} = 78.73\ \mathrm{GJ/h}$$

The hog fuel requirement would be approximately

$$\frac{79\ \mathrm{GJ/h}}{64\ \mathrm{GJ/h}} = 1.234$$ times the hog fuel requirement for a hog fuel/natural gas fired system.

(e) Scenario 2 - Replacement of Pressure Reducing Valves and Mechanical Drive Turbines

By comparing Figure 12-7 and 12-13 it is apparent that replacing both PRVs and some mechanical drive turbines, while using steam at 4240 kPa/400°C, requires an increase in steamflow from 244 t/h to 275 t/h for the example used in this report. The increase is required to maintain the same steamflow to the process after adding a 20 MW turbine/generator, removing the PRVs and removing

TABLE 12-10

HEAT RATES FOR COGENERATION AT PULP MILLS

Scenario	Fuel Type	Annual Fuel Requirement (GJ)	Annual Steam Requirement (GJ)	Annual Electricity Generated (GW·h)	Heat Rate (kJ/kW·h)
4240 kPa/400°C:					
Scenario 1	Hog Fuel	661 365	429 887	84.874	7792
	Hog Fuel/Natural Gas	632 184			7449
	Hog Fuel Oil	636 870			7504
Scenario 2	Hog Fuel	976 300	634 595	146.194	6678
	Hog Fuel/Natural Gas	933 228			6383
	Hog Fuel/Oil	940 141			6431
6310 kPa/445°C:					
Scenario 1	Hog Fuel	944 794	614 116	127.898	7387
	Hog Fuel/Natural Gas	903 112			7061
	Hog Fuel/Oil	909 801			7113
Scenario 2	Hog Fuel	1 270 585	825 880	190.898	6656
	Hog Fuel/Natural Gas	1 223 526			6409
	Hog Fuel/Oil	1 214 529			6362
8270 kPa/480°C:					
Scenario 1	Hog Fuel	1 132 294	735 991	165.866	6827
	Hog Fuel/Natural Gas	1 082 340			6525
	Hog Fuel/Oil	1 090 357			6574
Scenario 2	Hog Fuel	1 465 322	952 459	230.303	6363
	Hog Fuel/Natural Gas	1 400 675			6082
	Hog Fuel/Oil	1 411 050			6127

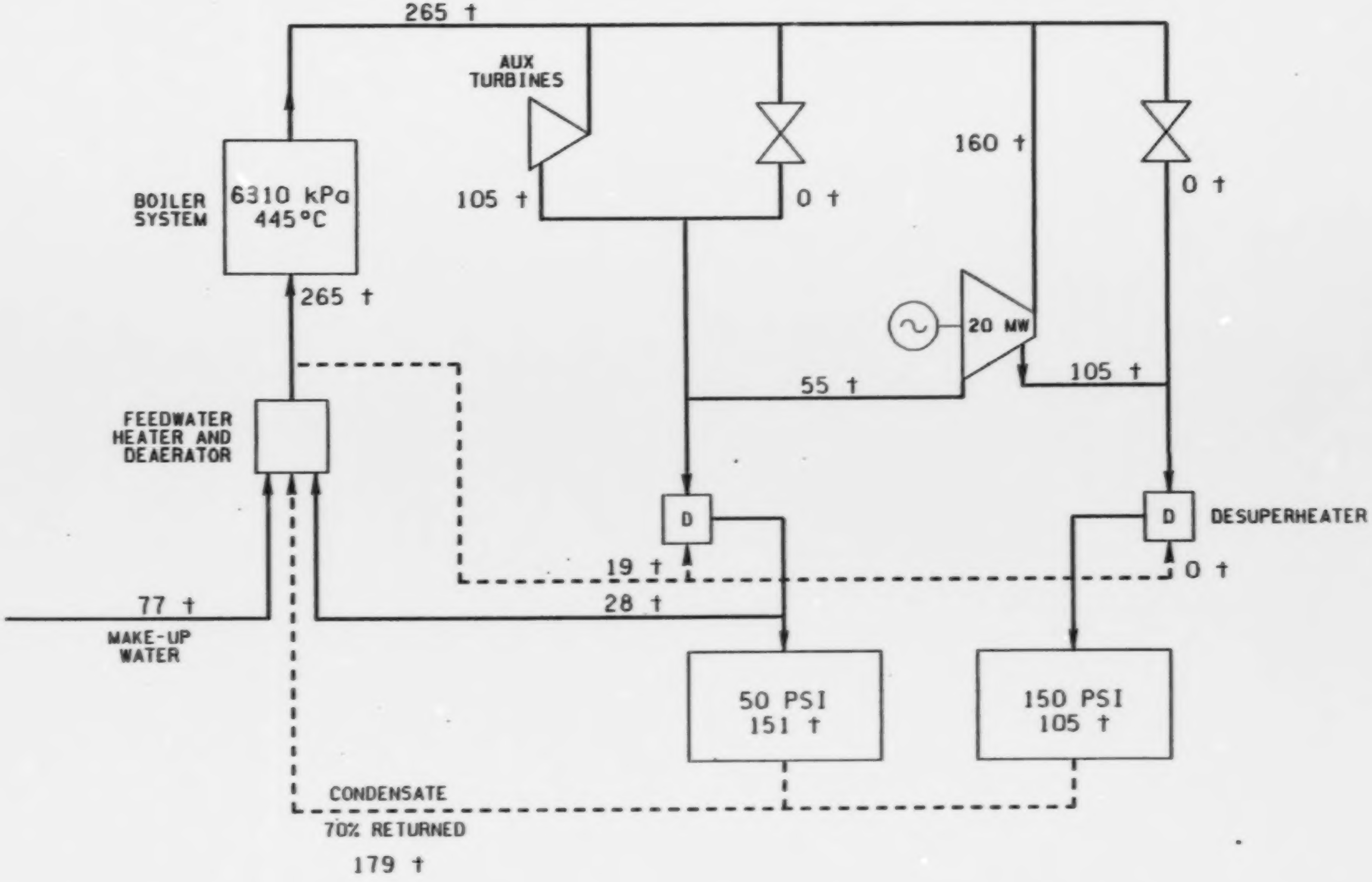

265 t
AUX TURBINES
160 t
BOILER SYSTEM
6310 kPa 445°C
105 t
0 t
0 t
265 t
20 MW
105 t
55 t
FEEDWATER HEATER AND DEAERATOR
D
D
DESUPERHEATER
19 t
0 t
77 t
28 t
MAKE-UP WATER
50 PSI 151 t
150 PSI 105 t
CONDENSATE
70% RETURNED
179 t

Figure 12 - 11

PULP MILL 6310 kPa STEAM SYSTEM WITH 20 MW STEAM TURBINE ADDED (SCENARIO 1)

- STEAM FLOW IN TONNES/HOUR

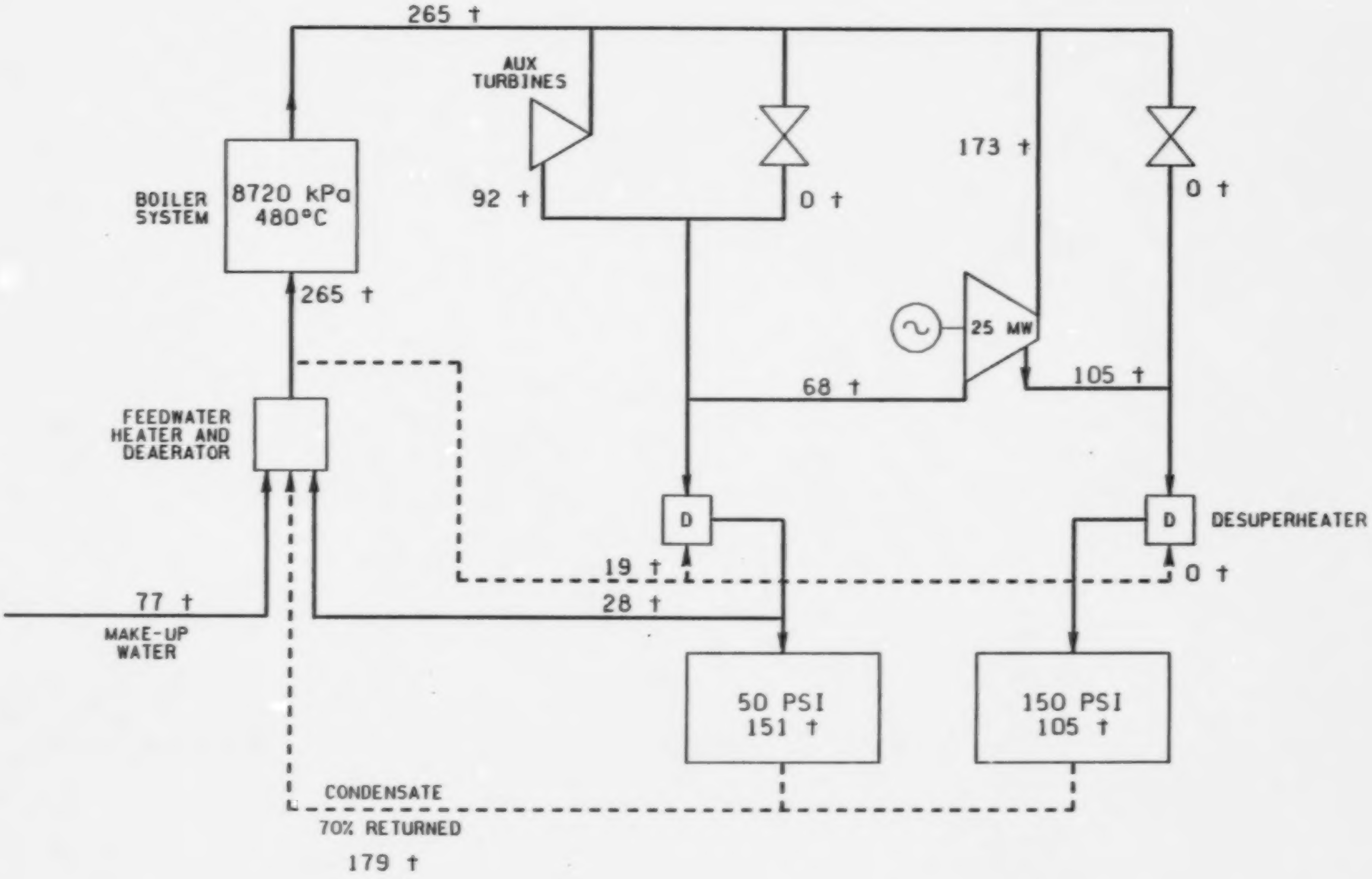

265 t
AUX TURBINES
BOILER SYSTEM
8720 kPa 480°C
92 t
0 t
173 t
0 t
265 t
25 MW
68 t
105 t
FEEDWATER HEATER AND DEAERATOR
D
D
DESUPERHEATER
19 t
0 t
77 t
28 t
MAKE-UP WATER
50 PSI 151 t
150 PSI 105 t
CONDENSATE
70% RETURNED
179 t

Figure 12 - 12

PULP MILL 8720 kPa STEAM SYSTEM WITH 25 MW STEAM TURBINE ADDED (SCENARIO 1)

- STEAM FLOW IN TONNES/HOUR

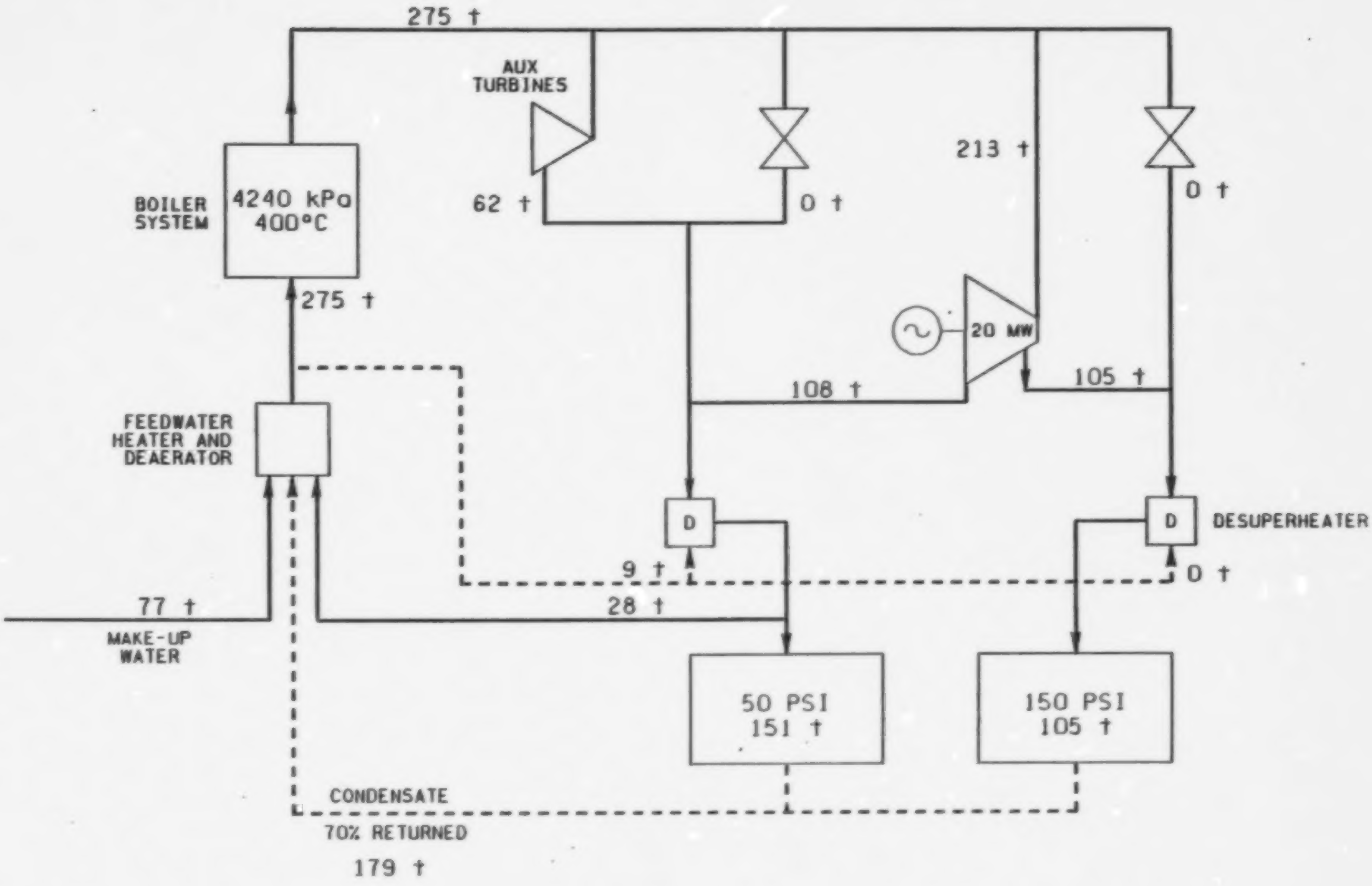

275 t
AUX TURBINES
62 t
0 t
213 t
0 t
BOILER SYSTEM
4240 kPa 400°C
275 t
20 MW
108 t
105 t
FEEDWATER HEATER AND DEAERATOR
D
D
DESUPERHEATER
9 t
0 t
77 t
MAKE-UP WATER
28 t
50 PSI 151 t
150 PSI 105 t
CONDENSATE
70% RETURNED
179 t

Figure 12 - 13

PULP MILL 4240 kPa STEAM SYSTEM WITH 20 MW STEAM TURBINE ADDED (SCENARIO 2)

- STEAM FLOW IN TONNES/HOUR

2

some of the mechanical drive turbines (Tables 7-8 and 8-3). Therefore, the average electricity generated would be

$$\frac{105\ \text{t/h}}{15.9\ \text{kg/kW}\cdot\text{h}} = 6\ 604\ \text{kW}\cdot\text{h}$$

$$\frac{108\ \text{t/h}}{10.0\ \text{kg/kW}\cdot\text{h}} = 10\ 800\ \text{kW}\cdot\text{h}$$

$$\text{Total} \qquad \overline{17\ 404\ \text{kW}\cdot\text{h}}$$

Assuming the plant operates 350 days/annum and 24 hours/day, the annual generation would be 146.26 GW·h. A 20 MW turbine/generator was selected. Therefore, the capacity factor would be

$$\frac{(146.2\ \text{GW}\cdot\text{h/a})(100)}{(20\ \text{MW})(8760\ \text{h/a})} = 84.3\%$$

The incremental boiler steam flow is estimated to be 31 t/h at 3205 kJ/kg (99.4 GJ/h) to generate 17.404 MW·h. As noted previously, the heating value of the boiler feedwater is 768 kJ/kg. Therefore, the additional fuel energy is

$$\frac{(3205\ \text{kJ/kg}\ 768\ \text{kJ/kg})(1000\ \text{kg/t})(31\ \text{t/h})}{(.65)(.85) + (.85)(.15)} = 111.1\ \text{GJ/h}$$

which is the steam requirement corrected for the weighted efficiencies of Interior B.C. hog fuel and natural gas firing. The heat rates for cogeneration at the pulp mills in these scenarios are summarized in Table 12-10. The annual incremental fuel requirements, based on the additional fuel energy requirement, would be 40 176 BDt of wood waste and 3 596 000 m^3 of natural gas.

Similar estimates of fuel requirements and electricity generation were prepared for boilers at 6310 kPa/445°C and 8720 kPa/480°C, for Coastal pulp mills which use residual oil as a fuel (Figures 12-14 and 12-15) and for boilers using only hog fuel.

The Capital costs and heat rates for Scenario 2 are summarized in Tables 129 and 12-10. Replacing steam turbine mechanical drive equipment with electric drive motors and related equipment is estimated to cost between \$116 and \$128/kW (1988\$); the \$116/kW estimate is used in this report. The estimate of this additional cost is based on the incremental electric capacity and the capital cost of PRV replacement.

(f) Simple Payback (After Tax)

In preparing the estimates for after tax internal rates of return (IRR's) the data for estimating simple payback is also produced. Estimates of IRR were generally calculated until a 20 percent hurdle rate was unattainable; at this point the preparation of estimates for higher cost scenarios was terminated. The after

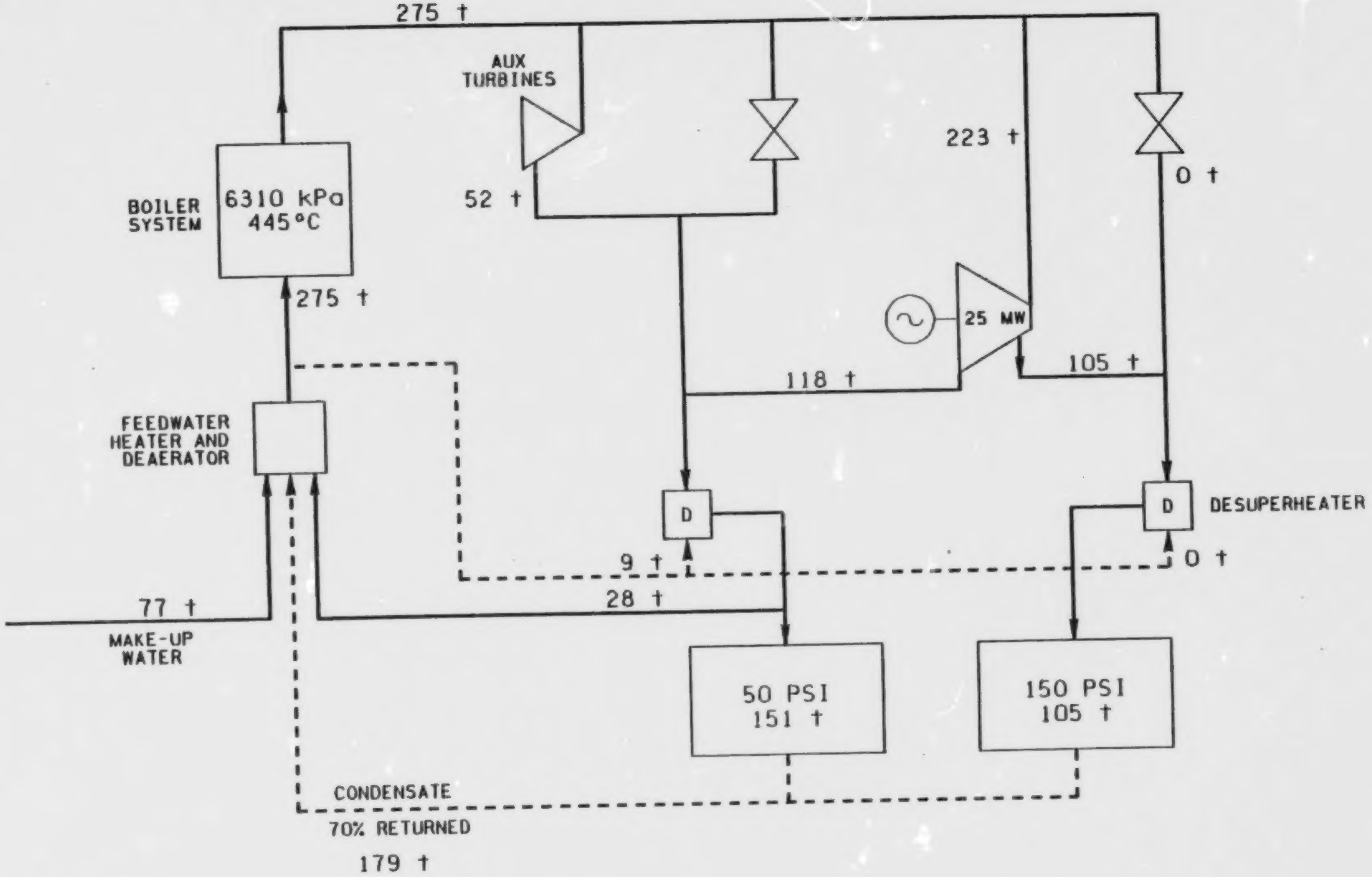

275 t
AUX TURBINES
52 t
223 t
0 t
BOILER SYSTEM
6310 kPa
445°C
275 t
25 MW
118 t
105 t
FEEDWATER HEATER AND DEAERATOR
D
D
DESUPERHEATER
9 t
0 t
77 t
28 t
MAKE-UP WATER
50 PSI
151 t
150 PSI
105 t
CONDENSATE
70% RETURNED
179 t

Figure 12 - 14

PULP MILL 6310 kPa STEAM SYSTEM WITH 25 MW STEAM TURBINE ADDED (SCENARIO 2)

- STEAM FLOW IN TONNES/HOUR

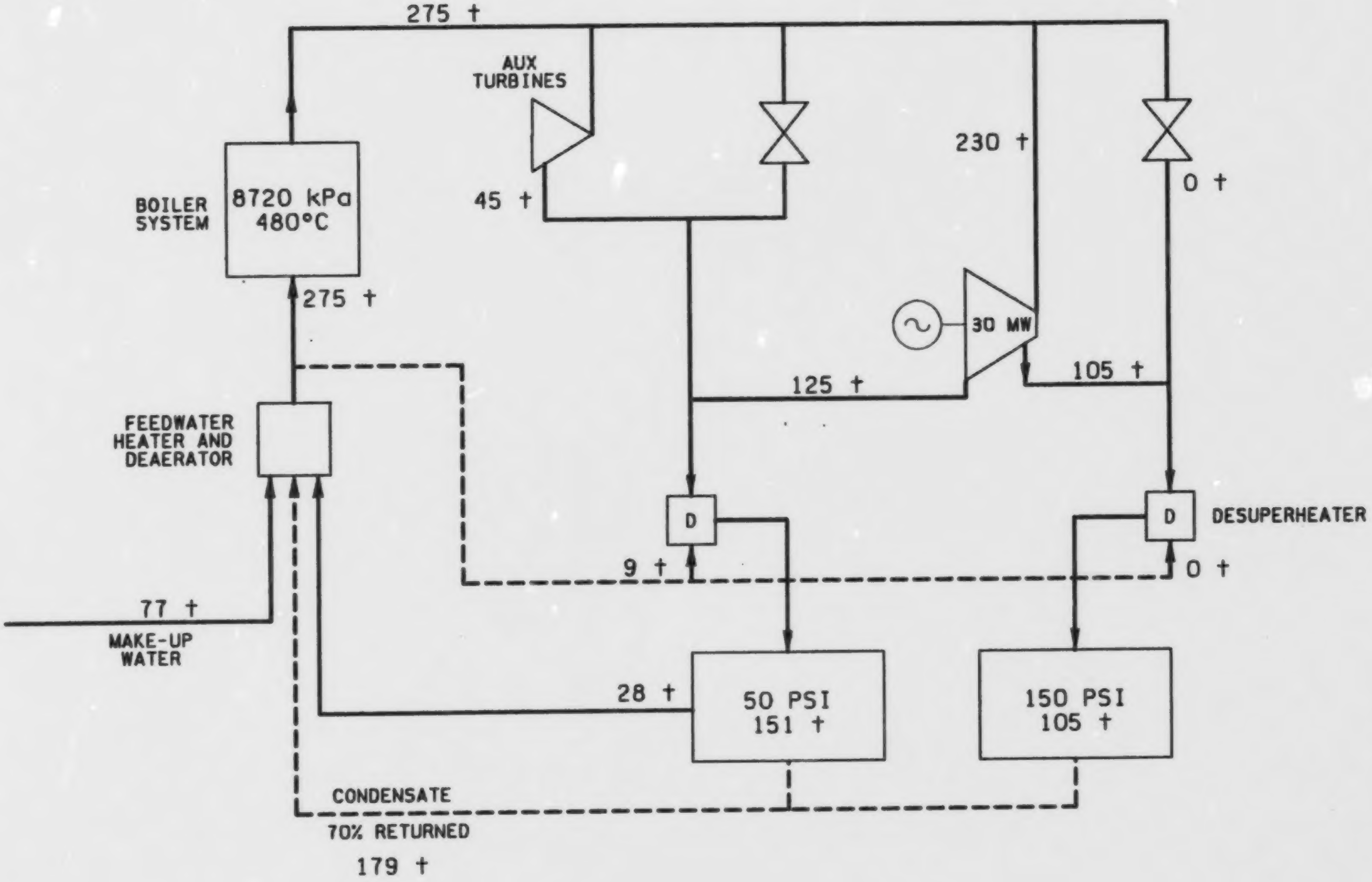

275 t
AUX TURBINES
BOILER SYSTEM
8720 kPa
480°C
45 t
230 t
0 t
275 t
30 MW
125 t
105 t
FEEDWATER HEATER AND DEAERATOR
D
D
DESUPERHEATER
9 t
0 t
77 t
MAKE-UP WATER
28 t
50 PSI
151 t
150 PSI
105 t
CONDENSATE
70% RETURNED
179 t

Figure 12 - 15

PULP MILL 8720 kPa STEAM SYSTEM WITH 30 MW STEAM TURBINE ADDED (SCENARIO 2)

- STEAM FLOW IN TONNES/HOUR

tax simple payback was used as a quick method of screening potential cogeneration projects. The fuel component of the steam costs were estimated to be $0.89, $1.09, $1.25, $1.41, $1.68, $2.12, $2.43, $3.81 and $3.93/GJ. Simple paybacks were estimated for each fuel component, capital cost, electricity value and for the two scenarios assuming PRV replacement and PRV and partial mechanical drive turbine replacement.

At 4240 kPa/400°C the simple payback periods for the alternatives which were evaluated ranged from 2.2 years, when the PRVs and some of the mechanical drive turbine capacity were replaced with turbine/generators and electric motors, to more than 9.0 years when only PRVs were replaced and other significant modifications were required at a high capital cost (Tables 12-11 and 12-12). At a capital cost of $6.955 M for PRV replacement and other minor improvements, steam costs of $1.68/GJ or less and the sale of electricity for 40 mills/kW•h, the payback is less than 3 years. Similarly, at a capital cost of $10.122 M for PRV and partial mechanical drive turbine replacement and steam costs of $2.45/GJ or less, the payback period is less than 3 years for the sale of electricity at 40 mills/kW•h and also less than 3 years for the sale of electricity at 35 mills/kW•h with steam costs of less than $2.12/GJ.

At 6310 kPa/445°C, the capital cost is higher than the capital cost at 4240 kPa/400°C. However, electricity generation is also increased (Table 12-9). With the replacement of PRVs and minor plant modifications, electricity generation is economical at electricity prices as low as 35 mills/kW•h assuming a steam cost of less than $1.41/GJ (Tables 12-13 and 12-14). In fact, replacements of PRVs along with some mechanical drive turbines and minor boiler modifications yield payback periods of less than 3 years over most steam prices. More expensive modifications produce payback periods of 3 years or more.

Some estimates of payback periods were also done at 8270 kPa/480°C in order to examine the economic advantage of a high pressure steam boiler (Tables 12-15 and 12-16). Electricity generation increases significantly, but it increases at a slower rate with increasing pressure. At 40 mills/kW•h and low capital cost, the payback period is less than 3 years for Scenario 1. At 35 and 40 mills/kW•h and low capital cost the payback period is commonly less than 3 years for Scenario 2. Payback periods were more than 3 years for the other alternatives which were estimated.

(g) Internal Rate of Return

As noted, the after tax internal rate of return (IRR) was also estimated. A hurdle rate of 20 percent was generally assumed for these estimates. The hurdle rate is the minimum acceptable IRR. Estimates were generally made for IRRs above the hurdle rate of 20 percent. In preparing these estimates it was common to

TABLE 12-11

SIMPLE PAYBACK AFTER TAX (YEARS)
@ 4240 kPa/400°C - HOG FUEL

Fuel Component of Steam Cost ($/GJ)	0.89			1.09			1.60			2.12		
Value of Electricity (mills/kW·h)	30	35	40	30	35	40	30	35	40	30	35	40
Capital Cost (k$)												
Scenario 1 - Annual Electricity Generation (Net): 84.9 GW·h												
6 955	3.5	2.9	2.7	3.7	3.0	2.7	4.2	3.4	2.9	4.9	3.8	3.1
10 739	-	4.6	3.9	-	4.8	4.1	-	-	4.4	-	-	5.1
14 319	-	-	5.4	-	-	-	-	-	-	-	-	-
21 477	-	-	-	-	-	-	-	-	-	-	-	-
Scenario 2 - Annual Electricity Generation (Net): 146.2 GW·h												
10 122	2.9	2.6	2.3	3.0	2.6	2.4	3.3	2.8	2.5	3.7	3.0	2.6
15 167	4.4	3.7	3.1	4.6	3.8	3.2	5.1	4.1	3.4	-	4.5	3.7
19 940	-	4.9	4.2	-	-	4.3	-	-	4.6	-	-	5.0
29 485	-	-	6.4	-	-	-	-	-	-	-	-	-

TABLE 12-12

SIMPLE PAYBACK AFTER TAX (YEARS)
@ 4240 kPa/400°C - HOG/NATURAL GAS OR OIL FUEL

Fuel Component of Steam Cost ($/GJ)	1.25			1.41			1.68			2.45			3.81			3.93		
Value of Electricity (mills/kW·h)	30	35	40	30	35	40	30	35	40	30	35	40	30	35	40	30	35	40
Capital Cost (k$)																		
Scenario 1 - Annual Electricity Generation (Net): 84.9 GW·h																		
6 955	3.8	3.1	2.8	4.0	3.2	2.8	4.3	3.4	2.9	5.4	4.1	3.3	10.3	6.4	4.6	-	-	4.8
10 739	-	5.0	4.2	-	5.1	4.3	-	-	4.5	-	-	5.2	-	-	-	-	-	-
14 319	-	6.8	5.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21 477	-	-	9.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Scenario 2 - Annual Electricity Generation (Net): 146.2 GW·h																		
10 122	3.1	2.7	2.4	3.2	2.7	2.4	3.4	2.8	2.5	4.0	3.1	2.7	6.3	4.3	3.3	-	4.5	3.4
15 167	4.7	3.9	3.3	-	4.0	3.3	-	4.2	3.5	-	4.8	3.9	-	-	5.1	-	-	-
19 940	-	5.2	4.4	-	-	4.5	-	-	4.7	-	-	-	-	-	-	-	-	-
29 485	-	-	6.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

TABLE 12-13

SIMPLE PAYBACK AFTER TAX (YEARS)
@ 6310 kPa/445°C - HOG FUEL

Fuel Component of Steam Cost ($/GJ)	0.89			1.09			1.60			2.12		
Value of Electricity (mills/kW•h)	30	35	40	30	35	40	30	35	40	30	35	40
Capital Cost (k$)												
Scenario 1 - Annual Electricity Generation (Net): 127.9 GW•h												
9 829	3.3	2.8	2.5	3.4	2.9	2.6	3.8	3.1	2.7	4.4	3.4	2.9
15 187	5.2	4.3	3.6	-	4.4	3.8	-	4.9	4.1	-	-	4.5
20 236	-	-	5.0	-	-	-	-	-	-	-	-	-
30 355	-	-	-	-	-	-	-	-	-	-	-	-
Scenario 2 - Annual Electricity Generation (Net): 190.9 GW•h												
12 516	2.8	2.5	2.2	2.9	2.6	2.3	3.1	2.7	2.4	3.5	2.9	2.5
18 834	4.2	3.5	3.0	4.3	3.6	3.1	4.8	3.9	3.3	-	4.3	3.5
24 789	5.6	4.6	4.0	-	4.8	4.1	-	-	4.4	-	-	4.7
36 720	-	-	6.1	-	-	-	-	-	-	-	-	-

TABLE 12-14

SIMPLE PAYBACK AFTER TAX (YEARS)
@ 6310 kPa/445°C - HOG/NATURAL GAS OR OIL FUEL

Fuel Component of Steam Cost ($/GJ)	1.25			1.41			1.68			2.45			3.81			3.93		
Value of Electricity (mills/kW•h)	30	35	40	30	35	40	30	35	40	30	35	40	30	35	40	30	35	40
Capital Cost (k$)																		
Scenario 1 - Annual Electricity Generation (Net): 127.9 GW•h																		
9 829	3.5	2.9	2.6	3.7	3.0	2.7	3.9	3.1	2.7	4.9	3.7	3.0	-	5.5	4.1	-	-	4.2
15 187	5.6	4.6	3.9	-	4.7	4.0	-	-	4.1	-	-	4.8	-	-	-	-	-	-
20 236	-	-	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30 355	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Scenario 2 - Annual Electricity Generation (Net): 190.9 GW•h																		
12 516	2.9	2.6	2.3	3.0	2.6	2.3	3.2	2.7	2.4	3.8	3.0	2.6	5.9	4.1	3.1	-	4.2	3.2
18 834	4.5	3.7	3.1	4.6	3.8	3.2	4.9	4.0	3.3	-	4.6	3.7	-	6.4	4.8	-	-	-
24 789	-	4.9	4.2	-	-	4.3	-	-	4.4	-	-	5.0	-	-	-	-	-	-
36 720	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

TABLE 12-15

SIMPLE PAYBACK AFTER TAX (YEARS)
@ 8720 kPa/480°C - HOG FUEL

Fuel Component of Steam Cost ($/GJ)	0.89			1.09			1.60			2.12		
Value of Electricity (mills/kW•h)	30	35	40	30	35	40	30	35	40	30	35	40
Capital Cost (k$)												
Scenario 1 - Annual Electricity Generation (Net): 165.9 GW•h												
13 214	3.3	2.9	2.6	3.5	2.9	2.6	3.9	3.1	2.8	4.4	3.4	2.9
20 416	5.3	4.4	3.7	-	4.5	3.9	-	5.0	4.2	-	-	4.5
27 205	-	-	5.1	-	-	-	-	-	-	-	-	-
40 807	-	-	-	-	-	-	-	-	-	-	-	-
Scenario 2 - Annual Electricity Generation (Net): 230.3 GW•h												
17 335	3.1	2.7	2.5	3.2	2.8	2.5	3.6	2.9	2.6	4.0	3.2	2.7
26 055	4.8	4.0	3.4	-	4.1	3.5	-	4.5	3.7	-	4.9	4.0
34 272	-	5.4	4.5	-	-	4.7	-	-	-	-	-	-
50 738	-	-	7.0	-	-	-	-	-	-	-	-	-

TABLE 12-16

SIMPLE PAYBACK AFTER TAX (YEARS)
@ 8720 kPa/480°C - HOG/NATURAL GAS OR OIL FUEL

Fuel Component of Steam Cost $/GJ	1.25			1.41		
Value of Electricity (mills/kW·h)	30	35	40	30	35	40
Scenario 1 - Annual Electricity Generation (Net): 165.9 GW·h						
	3.6	3.0	2.7	3.7	3.0	2.7
	-	4.7	3.9	-	4.8	4.0
	-	6.4	5.4	-	6.6	-
	-	10.2	-	-	10.6	-
Scenario 2 - Annual Electricity Generation (Net): 230.3 GW·h						
	3.3	2.8	2.5	3.4	2.9	2.6
	5.1	4.2	3.6	5.3	4.3	3.6
	-	5.7	4.8	-	5.8	-
	-	8.8	-	-	9.1	-

calculate only one IRR below the 20 percent hurdle rate for each capital cost.

The results are summarized in Tables 12-17 through 12-22 assuming steam conditions of 4240 kPa/400°C, 6310 kPa/445°C and 8720 kPa/480°C and 3 fuel types. In general, the after tax internal rates of return are only above the 20 percent hurdle rate if capital costs and steam costs are low and the value of electricity is high. Some estimates are above a 30 percent hurdle rate. The replacement of mechanical drive turbines improves the overall economics compared with replacing only pressure reducing valves.

Graphs of the relation between after tax internal rate of return and the fuel component of the steam cost were prepared for each capital cost and electricity value (Figures 12-16 through 12-25). They are an illustration of the information in Tables 12-17 through 12-21. The graphs can be used, in conjunction with the fuel cost information in Tables 12-5 and 12-7 as well as the steam flow estimates in Section 12.5, to project the fuel component of the steam cost and determine a revised after tax internal rate of return for other fuel costs.

(h) Unit Energy Cost

The scenarios were also compared on a unit energy cost basis to facilitate further comparison with B.C. Hydro projects (Appendix C). A 5 percent discount rate net of inflation was selected because it was commonly used in B.C. Hydro comparisons for 1988. The construction time is assumed to be one year for each scenario. This is undoubtedly an oversimplification for the higher cost scenarios, but was done to provide uniform treatment of all comparisons. A 10 percent discount rate was selected for some alternatives to evaluate the impact of an extraordinary increase in interest rates.

If the long-term marginal cost of electricity to B.C. Hydro of 35 mills/kW·h (1988$) is accepted as the upper limit of generation cost at a 5 percent discount rate, each scenario can be compared to this standard. The results are summarized in Tables 12-23 through 12-28. The unit energy costs range from 11.3 mills/kW·h for replacement of PRVs and mechanical drive turbines at 6310 kPa/445°C with low capital cost, interest rate and fuel cost to 58.3 mills/kW·h for replacement of PRVs only at high capital cost, interest rate and fuel cost. The unit energy cost of many of the alternatives examined in the sensitivity analyses are below B.C. Hydro's long-term marginal cost of electricity (i.e. 35 mills/kW·h).

Figures 12-26 through 12-32 illustrate the distribution of unit energy costs and the effect of the fuel component of the steam cost, capital cost and interest rate on them. These graphs can be projected to lower fuel components of steam costs.

TABLE 12-17

AFTER TAX INTERNAL RATE OF RETURN (%)
@ 4240 kPa/400°C - HOG FUEL

Fuel Component of Steam Cost ($/GJ)	0.89			1.09			1.60			2.12		
Value of Electricity (mills/kW•h)	30	35	40	30	35	40	30	35	40	30	35	40
Capital Cost (k$)												
Scenario 1 - Annual Electricity Generation (Net): 84.9 GW•h												
6 955	25.2	29.4	33.4	24.2	28.5	32.5	21.8	26.2	30.4	19.3	23.8	28.1
10 739	-	20.2	23.1	-	19.5	22.5	-	-	20.9	-	-	19.2
14 319	-	-	17.8	-	-	-	-	-	-	-	-	-
21 477	-	-	-	-	-	-	-	-	-	-	-	-
Scenario 2 - Annual Electricity Generation (Net): 146.2 GW•h												
10 122	29.7	34.4	39.0	28.8	33.6	38.2	26.5	31.4	36.1	24.1	29.1	33.9
15 167	21.0	24.5	27.8	20.3	23.9	27.2	18.5	22.2	25.7	-	20.5	24.1
19 940	-	19.2	22.0	-	-	21.5	-	-	20.2	-	-	18.9
29 485	-	-	15.2	-	-	-	-	-	-	-	-	-

TABLE 12-18

AFTER TAX INTERNAL RATE OF RETURN (%)
@ 4240 kPa/400°C - HOG/NATURAL GAS OR OIL FUEL

Fuel Component of Steam Cost ($/GJ)	1.25			1.41			1.68			2.45			3.81			3.93		
Value of Electricity (mills/kW·h)	30	35	40	30	35	40	30	35	40	30	35	40	30	35	40	30	35	40
Capital Cost (k$)																		
Scenario 1 - Annual Electricity Generation (Net): 84.9 GW·h																		
6 955	23.5	27.8	31.8	22.8	27.1	31.2	21.5	25.9	30.0	17.6	22.3	26.6	9.2	15.3	20.2	-	-	19.6
10 739	15.7	19.0	22.0	-	-	21.5	-	-	20.6	-	-	18.1	-	-	-	-	-	-
14 319	-	-	16.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21 477	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Scenario 2 - Annual Electricity Generation (Net): 146.2 GW·h																		
10 122	28.1	32.9	37.5	27.4	32.2	36.9	26.2	31.0	35.7	22.5	27.6	32.4	15.5	21.3	26.5	-	20.7	25.9
15 167	19.7	23.3	26.7	-	22.8	26.3	-	22.0	25.4	-	19.4	23.0	-	-	18.5	-	-	-
19 940	-	18.2	21.1	-	-	20.7	-	-	20.0	-	-	-	-	-	-	-	-	-
29 485	-	-	14.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

TABLE 12-19

AFTER TAX INTERNAL RATE OF RETURN (%)
@ 6310 kPa/445°C - HOG FUEL

Fuel Component of Steam Cost ($/GJ)	0.89			1.09			1.60			2.12		
Value of Electricity (mills/kW•h)	30	35	40	30	35	40	30	35	40	30	35	40
Capital Cost (k$)												
			Scenario 1 - Annual Electricity Generation (Net): 127.9 GW•h									
9 829	26.8	31.1	35.4	25.9	30.3	34.6	23.5	28.1	32.4	21.0	25.7	30.2
15 187	18.2	21.5	24.6	-	20.9	23.9	-	19.2	22.4	-	-	20.7
20 236	-	-	19.0	-	-	-	-	-	-	-	-	-
30 355	-	-	-	-	-	-	-	-	-	-	-	-
			Scenario 2 - Annual Electricity Generation (Net): 190.9 GW•h									
12 516	31.1	36.0	40.8	30.2	35.2	40.0	27.8	32.9	37.8	25.3	30.5	35.5
18 834	21.9	25.6	29.1	21.2	24.9	28.4	19.4	23.2	26.8	-	21.5	25.2
24 789	17.0	20.1	23.0	-	19.6	22.5	-	-	21.1	-	-	19.7
36 720	-	-	16.0	-	-	-	-	-	-	-	-	-

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TABLE 12-20

AFTER TAX INTERNAL RATE OF RETURN (%)
@ 6310 kPa/445°C - HOG/NATURAL GAS OR OIL FUEL

Fuel Component of Steam Cost ($/GJ)	1.25			1.41			1.68			2.45			3.81			3.93		
Value of Electricity (mills/kW•h)	30	35	40	30	35	40	30	35	40	30	35	40	30	35	40	30	35	40
Capital Cost (k$)																		
Scenario 1 - Annual Electricity Generation (Net): 127.9 GW•h																		
9 829	25.2	29.6	33.9	24.4	28.9	33.2	23.1	27.7	32.1	19.4	24.2	28.7	-	17.4	22.4	-	-	21.9
15 187	17.0	20.3	23.4	-	19.8	22.9	-	-	22.1	-	-	19.7	-	-	-	-	-	-
20 236	-	-	18.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30 355	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Scenario 2 - Annual Electricity Generation (Net): 190.9 GW•h																		
12 516	29.4	34.4	39.3	28.7	33.7	38.6	27.4	32.5	37.4	23.7	29.0	34.0	16.4	22.4	27.8	-	21.8	27.2
18 834	20.7	24.4	27.9	20.1	23.9	27.4	19.2	23.0	26.6	-	20.3	24.1	-	15.2	19.4	-	-	-
24 789	-	19.1	22.1	-	-	21.6	-	-	20.9	-	-	18.8	-	-	-	-	-	-
36 720	-	-	15.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

TABLE 12-21

AFTER TAX INTERNAL RATE OF RETURN (%)
@ 8720 kPa/480°C HOG FUEL

Fuel Component of Steam Cost ($/GJ)	0.89			1.09			1.60			2.12		
Value of Electricity (mills/kW•h)	30	35	40	30	35	40	30	35	40	30	35	40
Capital Cost (k$)												
Scenario 1 - Annual Electricity Generation (Net): 165.9 GW•h												
13 214	26.3	30.6	34.7	25.5	29.8	33.9	23.4	27.8	32.0	21.1	25.7	29.9
20 416	17.9	21.0	24.0	-	20.4	23.5	-	19.0	22.0	-	-	20.6
27 205	-	-	18.6	-	-	-	-	-	-	-	-	-
40 807	-	-	-	-	-	-	-	-	-	-	-	-
Scenario 2 - Annual Electricity Generation (Net): 230.3 GW•h												
17 335	27.9	32.3	36.6	27.1	31.5	35.8	25.0	29.6	33.9	22.9	27.5	32.0
26 055	19.5	22.8	26.0	-	22.3	25.4	-	20.8	24.1	-	19.3	22.6
34 272	-	17.8	20.4	-	-	20.0	-	-	-	-	-	-
50 738	-	-	13.9	-	-	-	-	-	-	-	-	-

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TABLE 12-22

AFTER TAX INTERNAL RATE OF RETURN (%) @ 8720 kPa/480°C - HOG/NATURAL GAS OR OIL FUEL

Fuel Component of Steam Cost $/GJ	1.25			1.41		
Value of Electricity (mills/kW·h)	30	35	40	30	35	40
Capital Cost (k$)						
Scenario 1 - Annual Electricity Generation (Net): 165.9 GW·h						
13 214	24.8	29.1	33.3	24.2	28.5	32.7
20 416	-	19.3	23.0	-	18.9	22.6
27 205	-	15.2	17.7	-	14.8	-
40 807	-	9.3	-	-	8.9	-
Scenario 2 - Annual Electricity Generation (Net): 230.3 GW·h						
17 335	26.4	30.9	35.2	25.8	30.3	34.6
26 055	18.4	21.8	25.0	17.9	21.4	24.6
34 272	-	16.9	19.6	-	16.5	-
50 738	-	11.0	-	-	10.7	-

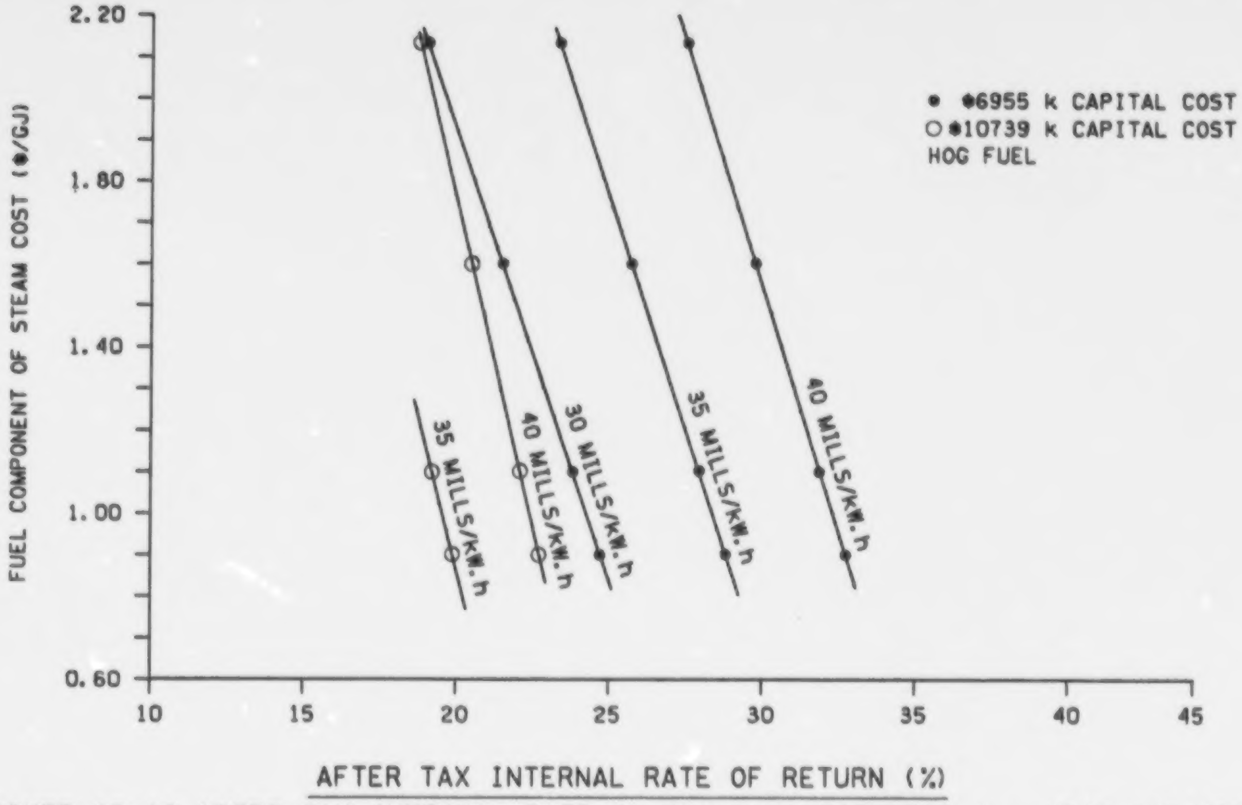

FIGURE 12-16 AFTER TAX INTERNAL RATE OF RETURN - SCENARIO 1 - 4240 kPa/400°C

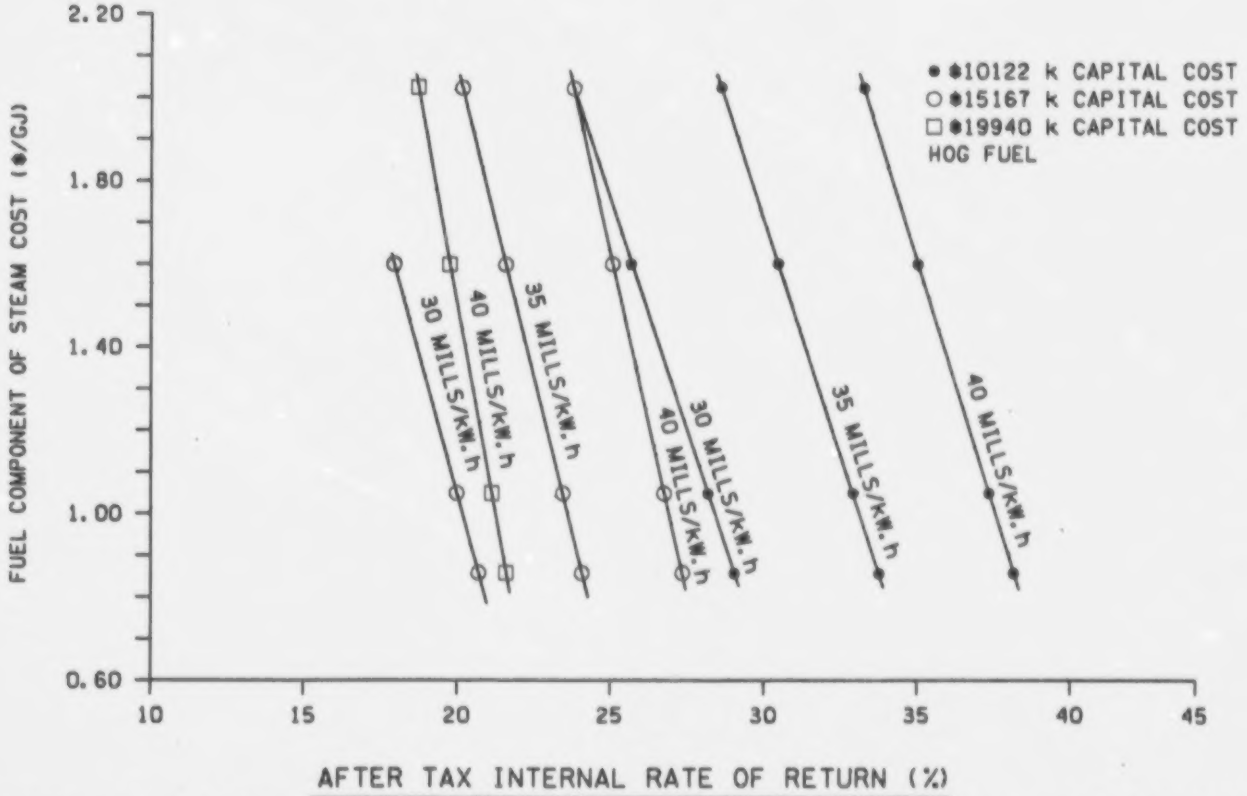

FIGURE 12-17 AFTER TAX INTERNAL RATE OF RETURN - SCENARIO 2 - 4240 kPa/400°C

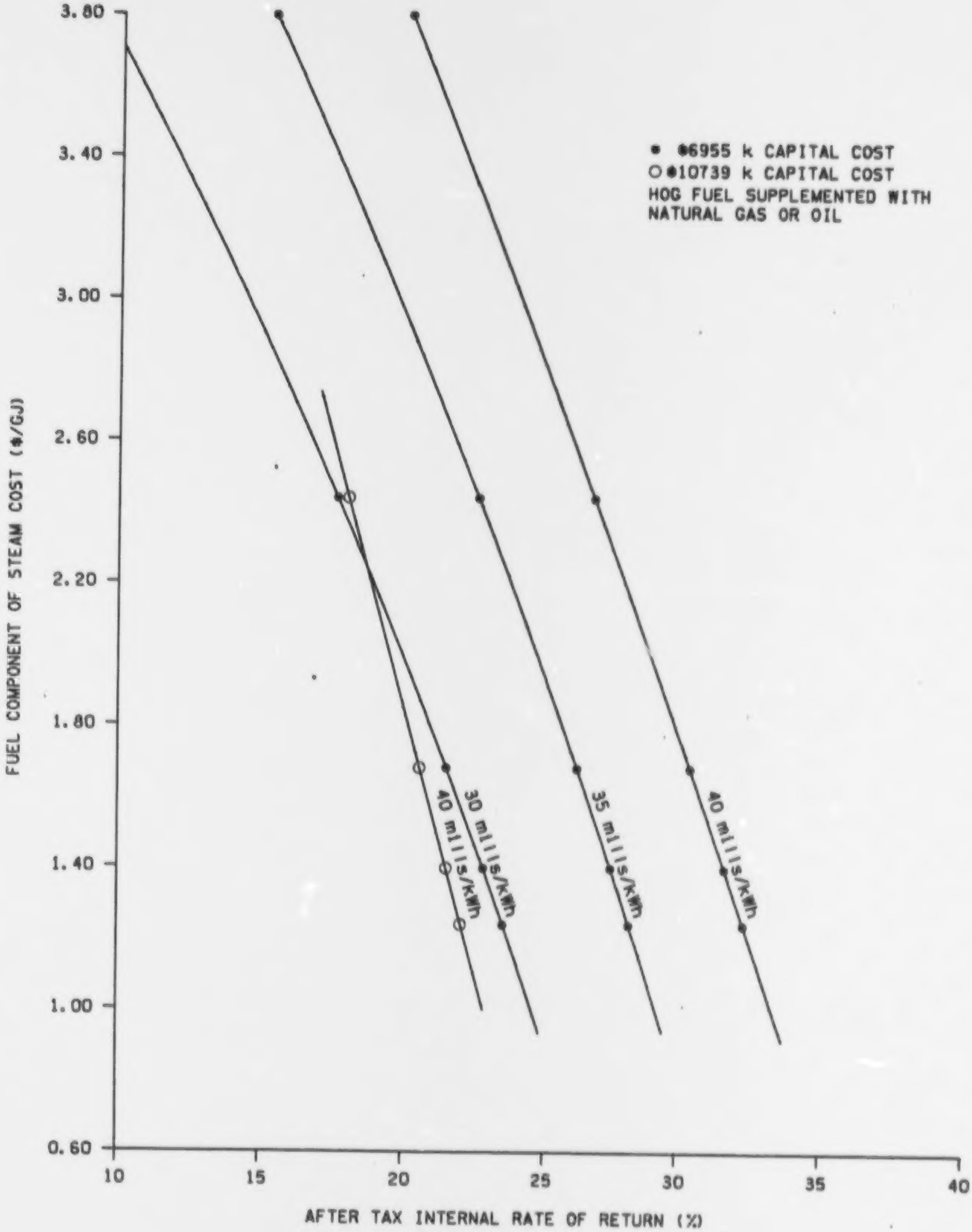

Figure 12 - 18

AFTER TAX INTERNAL RATE OF RETURN - SCENARIO 1 - 4240 kPa/400° C

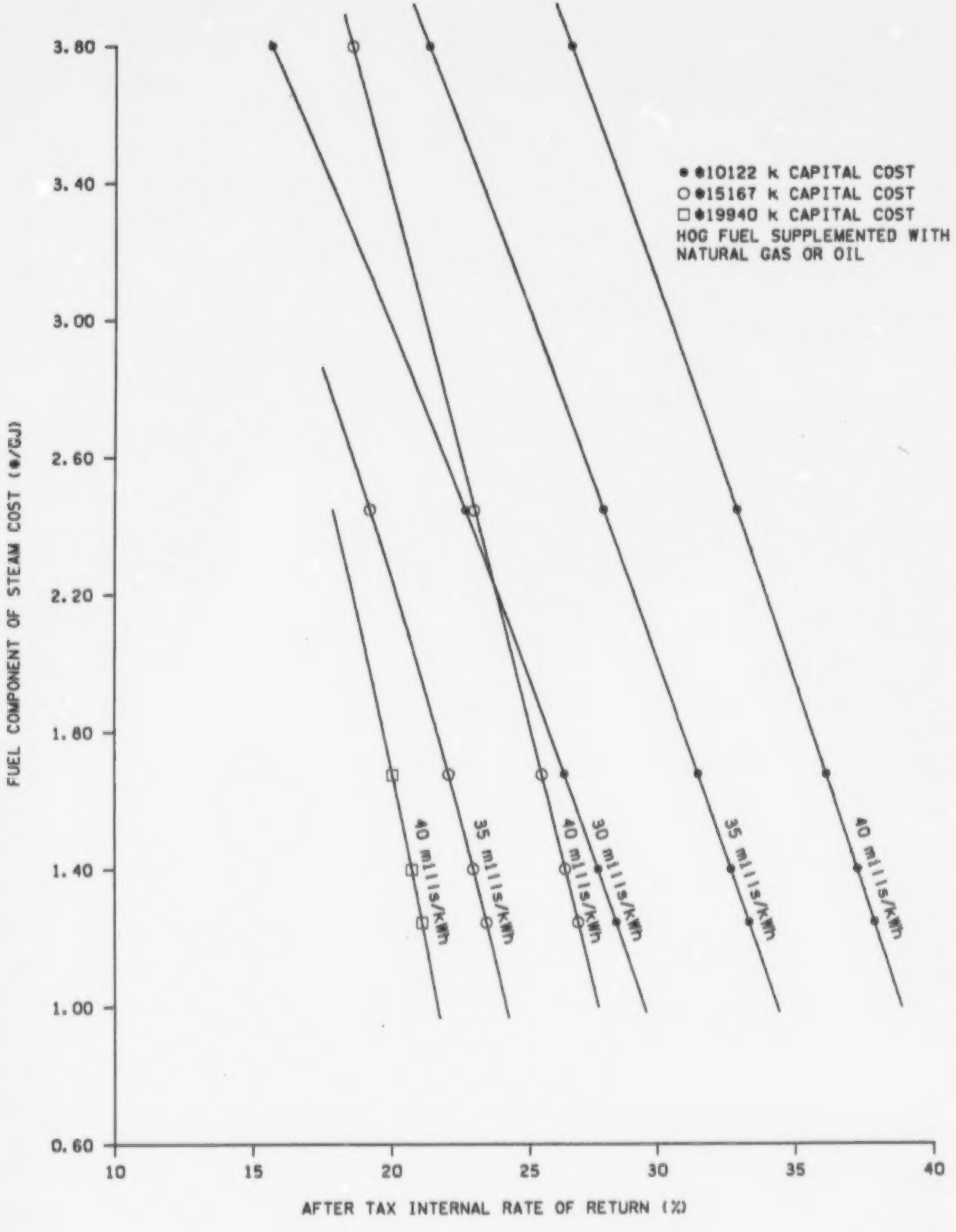

Figure 12 - 19

AFTER TAX INTERNAL RATE OF RETURN - SCENARIO 2 - 4240 kPa/400° C

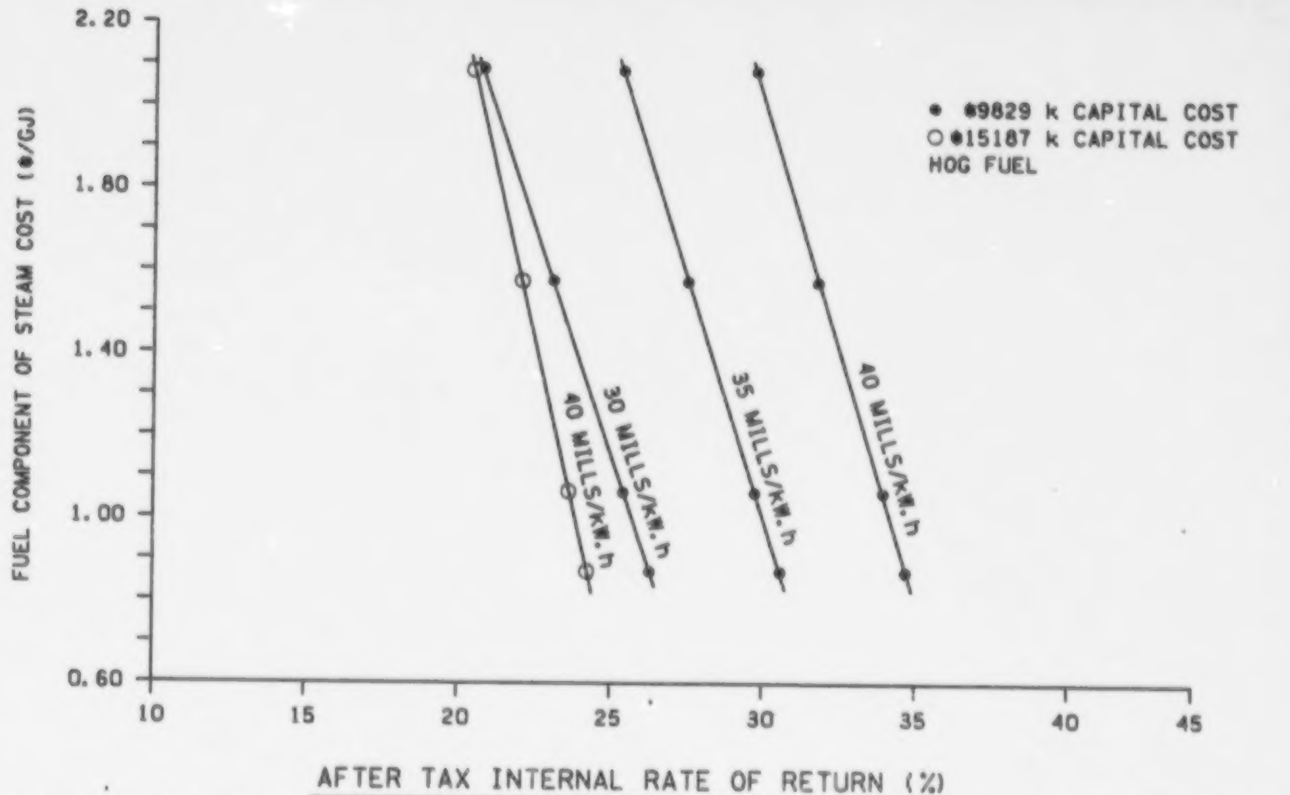

FIGURE 12-20 AFTER TAX INTERNAL RATE OF RETURN - SCENARIO 1 - 6310 kPa/445°C

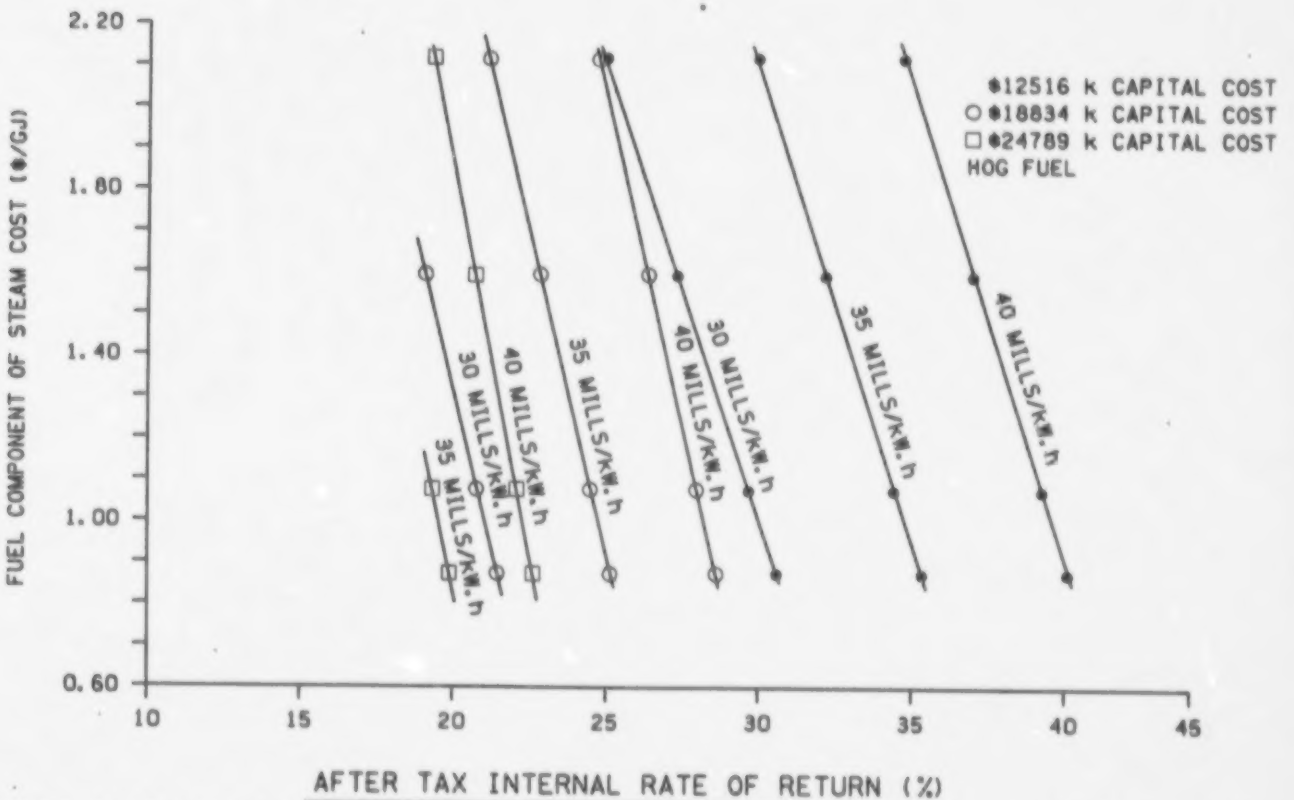

FIGURE 12-21 AFTER TAX INTERNAL RATE OF RETURN - SCENARIO 2 - 6310 kPa/445°C

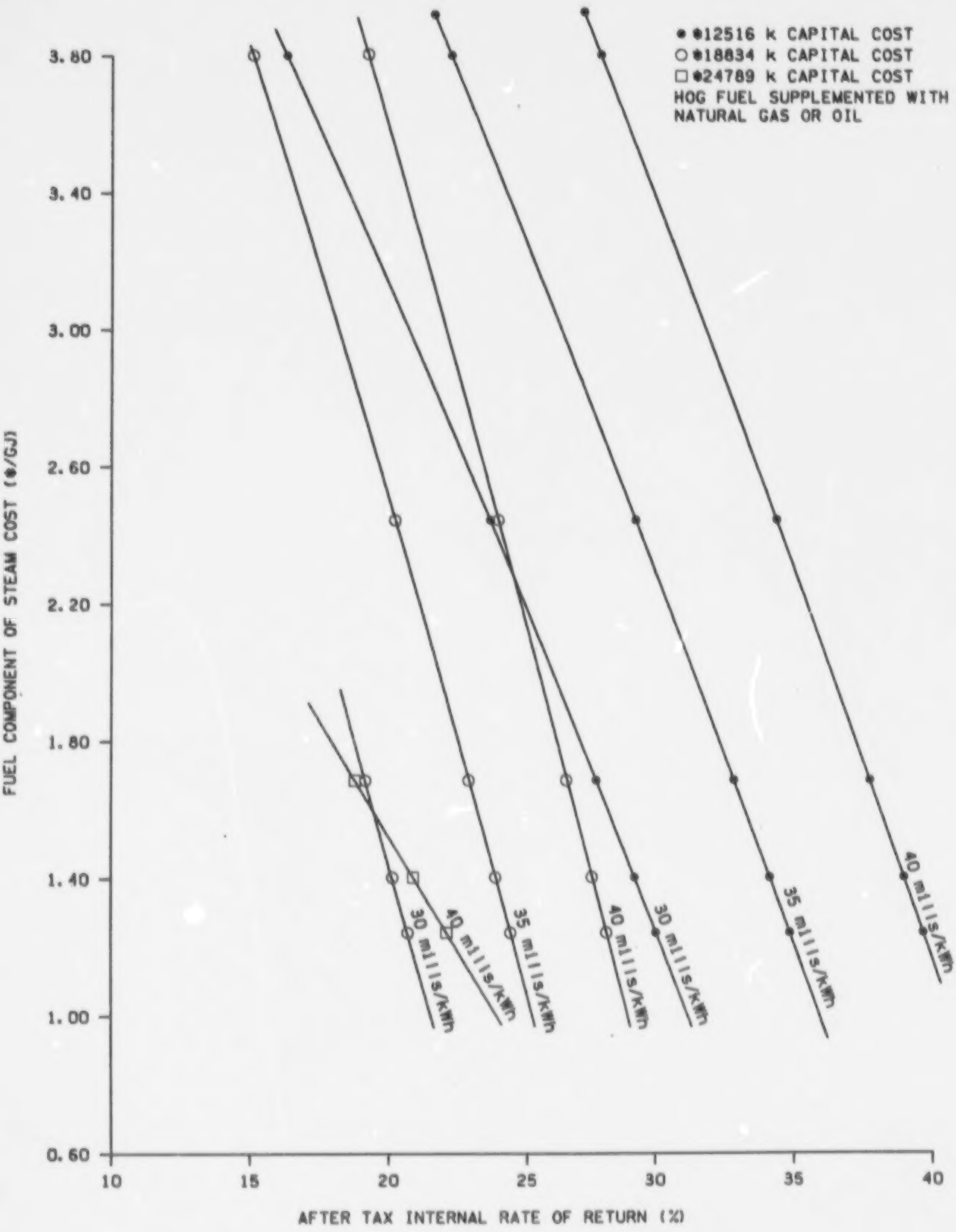

Figure 12 - 23

AFTER TAX INTERNAL RATE OF RETURN - SCENARIO 2 - 6310 kPa/445° C

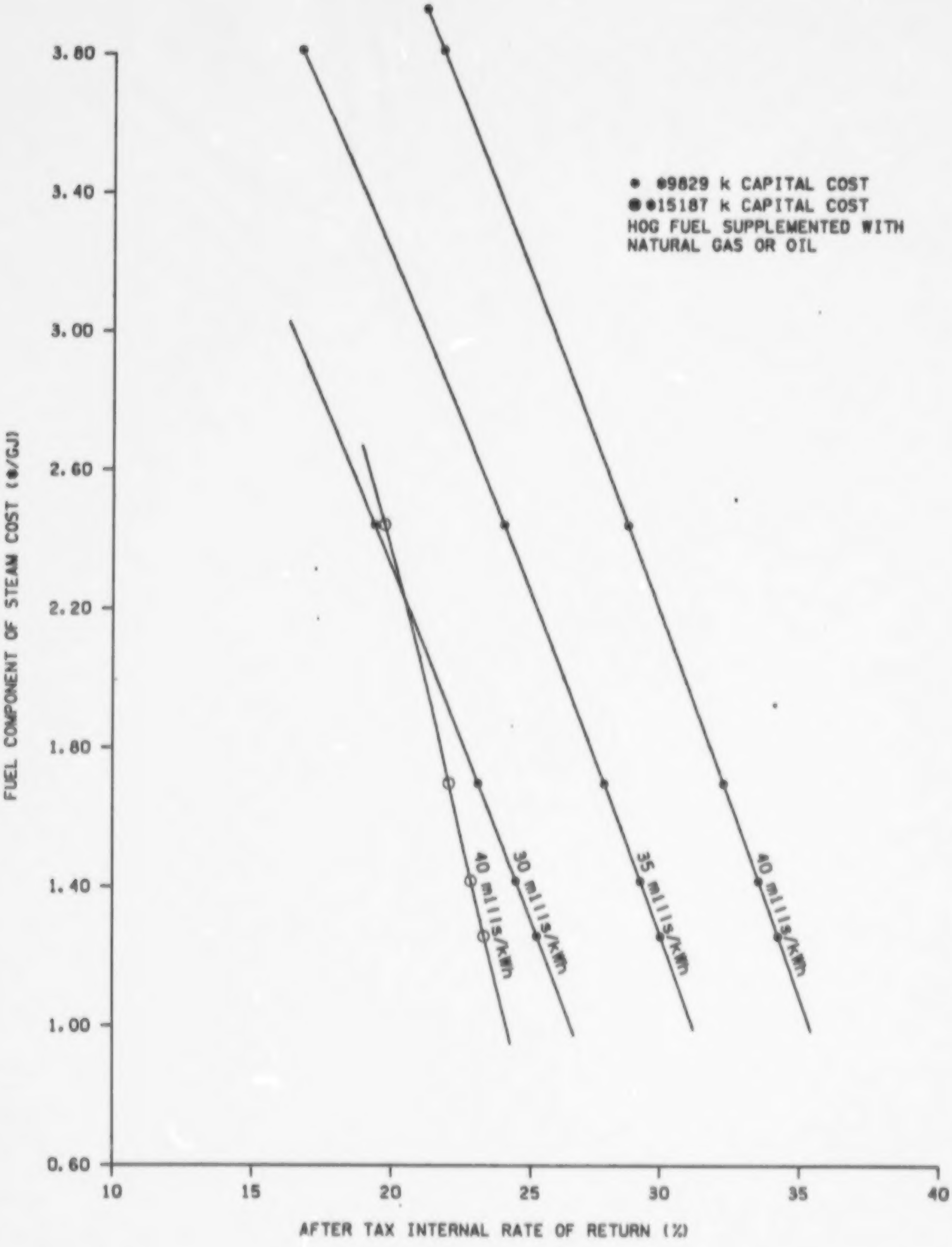

Figure 12 - 22

AFTER TAX INTERNAL RATE OF RETURN - SCENARIO 1 - 6310 kPa/445° C

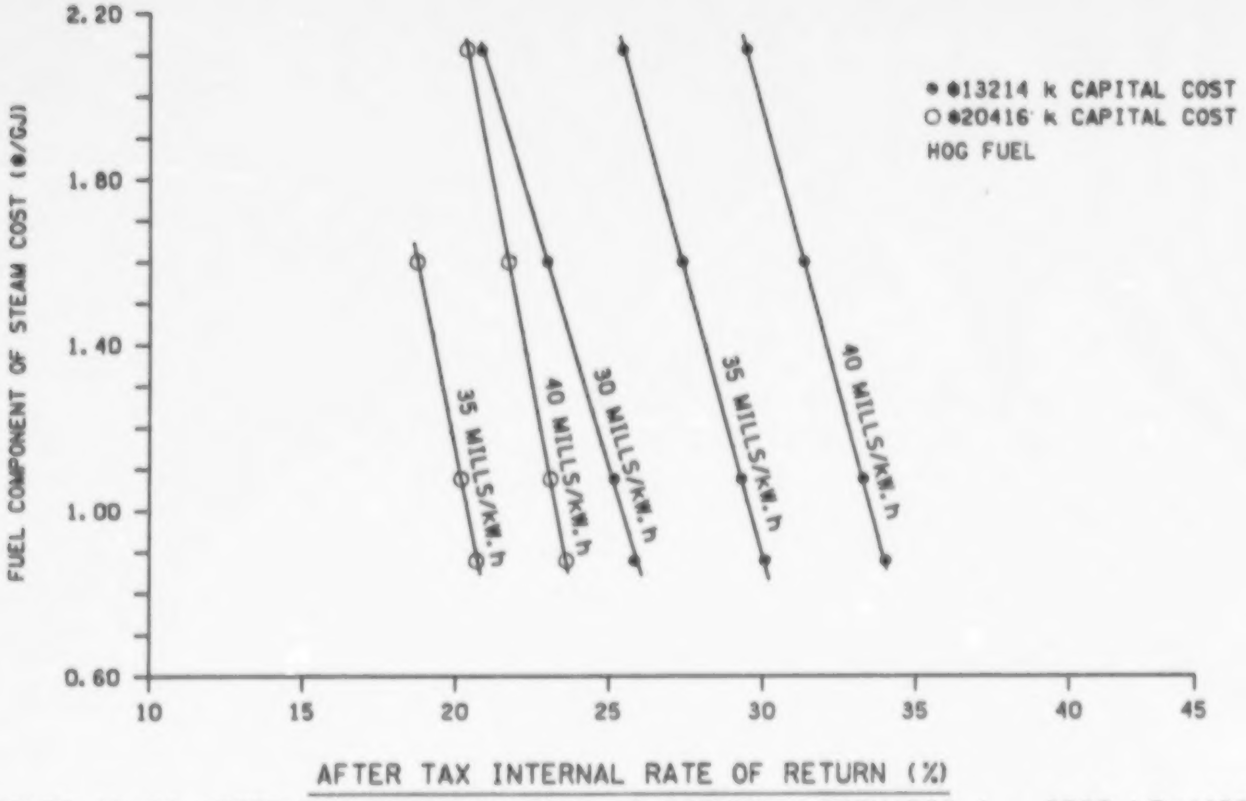

FIGURE 12-24 AFTER TAX INTERNAL RATE OF RETURN - SCENARIO 1 - 8720 kPa/480°C

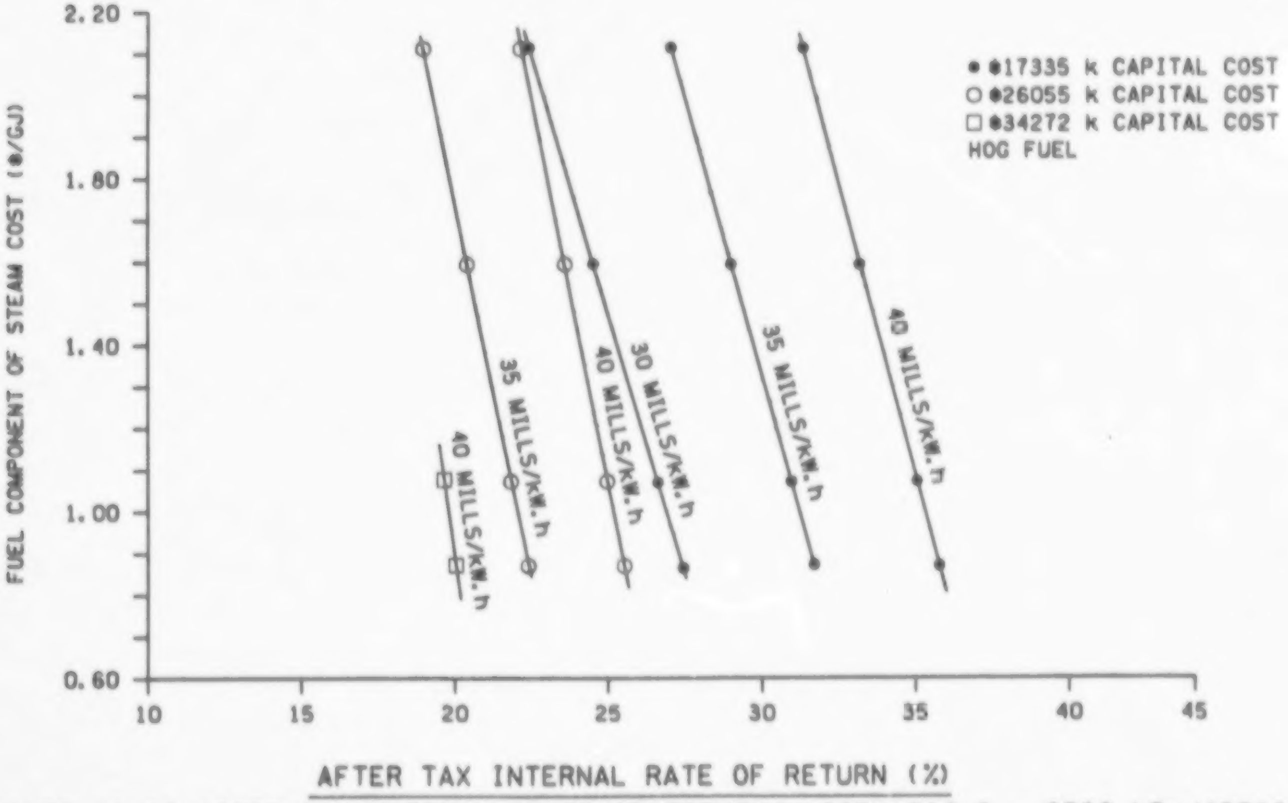

FIGURE 12-25 AFTER TAX INTERNAL RATE OF RETURN - SCENARIO 2 - 8720 kPa/480°C

TABLE 12-23

UNIT ENERGY COST (mills/kW·h)
@ 4240 kPa/400°C - HOG FUEL[*1]

Fuel Component of Steam Cost $/GJ	0.89	1.09	1.60	2.12
Capital Cost (k$)				
Scenario 1 - Annual Electricity Generation (Net): 84.9 GW·h				
6 955	13.77	14.78	17.37	20.00
10 739	18.76	19.78	22.46	24.99
14 319	23.48	24.71	27.26	29.87
21 477	32.92	33.89	36.45	39.06
Scenario 2 - Annual Electricity Generation (Net): 146.2 GW·h				
10 122	11.74	12.61	14.82	17.08
15 167	15.61	16.48	18.69	20.95
19 940	19.26	20.13	22.34	24.60
29 485	26.57	27.44	29.65	31.91

NOTE: [*1] @ 5% net interest rate.

TABLE 12-24

UNIT ENERGY COST (mills/kW·h)
@ 4240 kPa/400°C - HOG/NATURAL GAS OR OIL FUEL

Fuel Component of Steam Cost ($/GJ)	1.25		1.41		1.68		2.45		3.81		3.93	
Interest Rate (%)	5	10	5	10	5	10	5	10	5	10	5	10
Capital Cost (k$)												
Scenario 1 - Annual Electricity Generation (Net): 84.9 GW·h												
6 955	15.6	18.9	16.5	19.7	17.8	21.0	21.7	24.9	28.6	31.8	29.2	32.4
10 739	20.6	25.6	21.4	26.4	22.8	27.8	26.7	31.7	33.6	38.9	34.2	39.2
14 319	25.4	32.0	26.2	32.8	27.5	34.2	31.4	38.1	38.3	44.9	38.9	45.6
21 477	34.8	44.7	35.6	45.5	37.0	46.9	40.9	50.8	47.8	57.7	48.4	58.3
Scenario 2 - Annual Electricity Generation (Net): 146.2 GW·h												
10 122	13.3	16.0	14.0	16.7	15.2	17.9	18.5	21.2	24.4	27.1	24.9	27.7
15 167	17.2	21.2	17.9	21.9	19.0	23.1	22.4	26.5	28.3	32.4	28.8	32.9
19 940	20.8	26.2	21.5	26.9	22.7	28.1	26.0	31.4	32.0	37.3	32.5	37.8
29 485	28.1	36.0	28.8	36.7	30.0	37.9	33.3	41.2	39.2	47.2	39.8	47.7

TABLE 12-25

UNIT ENERGY COST (mills/kW·h) @ 6310 kPa/445°C - HOG FUEL[*1]

Fuel Component of Steam Cost $/GJ	0.89	1.09	1.60	2.12
Capital Cost (k$)				
Scenario 1 - Annual Electricity Generation (Net): 127.9 GW·h				
9 829	13.01	13.97	16.42	18.92
15 187	17.70	18.66	21.11	23.61
20 236	22.12	23.08	25.53	28.02
30 355	30.97	31.92	34.38	36.88
Scenario 2 - Annual Electricity Generation (Net): 190.9 GW·h				
12 516	11.30	12.16	14.37	16.62
18 834	15.01	15.88	18.08	20.33
24 789	18.50	19.37	21.58	23.82
36 720	25.50	26.34	28.54	30.78

NOTE: [*1] @ 5% net interest rate.

TABLE 12-26

UNIT ENERGY COST (mills/kW•h)
@ 6310 kPa/445°C - HOG/NATURAL GAS OR OIL FUEL

Fuel Component of Steam Cost ($/GJ)	1.25		1.41		1.68		2.45		3.81		3.93	
Interest Rate (%)	5	10	5	10	5	10	5	10	5	10	5	10
Capital Cost (k$)												
Scenario 1 - Annual Electricity Generation (Net): 127.9 GW•h												
9 829	14.7	17.8	15.5	18.5	16.8	19.8	20.5	23.5	27.0	30.0	27.6	30.6
15 187	19.4	24.1	20.2	24.9	21.5	26.2	25.2	30.0	31.7	36.4	32.3	37.0
20 236	23.8	30.1	24.6	30.8	25.9	32.1	29.6	35.8	36.1	42.3	36.7	42.9
30 355	32.7	42.0	33.5	42.8	34.8	44.1	38.5	47.8	45.0	54.3	45.6	54.9
Scenario 2 - Annual Electricity Generation (Net): 190.9 GW•h												
12 516	12.9	15.5	13.6	16.1	14.7	17.3	18.1	20.6	24.0	26.5	24.5	27.0
18 834	16.7	20.5	17.3	21.1	18.4	22.3	21.8	25.6	27.7	31.5	28.2	32.0
24 789	20.1	25.2	20.8	25.9	21.9	27.0	25.3	30.4	31.2	36.2	31.7	36.8
36 720	27.1	34.6	27.8	35.3	28.9	36.5	32.3	39.8	38.2	45.7	38.7	46.2

TABLE 12-27

UNIT ENERGY COST (mills/kW·h)
@ 8720 kPa/480°C - HOG FUEL[*1]

Fuel Component of Steam Cost $/GJ	0.89	1.09	1.60	2.12
Capital Cost (k$)				
Scenario 1 - Annual Electricity Generation (Net): 165.9 GW·h				
13 214	13.00	13.88	16.14	18.45
20 416	17.86	18.75	21.01	23.32
27 205	22.44	23.33	25.59	27.90
40 807	31.62	32.50	34.77	37.07
Scenario 2 - Annual Electricity Generation (Net): 230.3 GW·h				
17 335	12.24	13.06	15.17	17.32
26 055	16.48	17.30	19.41	21.56
34 272	20.47	21.30	23.41	25.56
50 738	28.48	29.31	31.79	33.57

NOTE: [*1] @ 5% net interest rate.

TABLE 12-28

UNIT ENERGY COST (mills/kW·h)
@ 8720 kPa/480°C - HOG/NATURAL GAS OR OIL FUEL

Fuel Component of Steam Cost $/GJ	1.25		1.41	
Interest Rate (%)	5	10	5	10
Capital Cost (k$)				
Scenario 1 - Annual Electricity Generation (Net): 165.9 GW·h				
13 214	14.6	17.7	15.3	18.4
20 416	19.5	24.3	20.2	25.0
27 205	24.0	30.4	24.8	31.2
40 807	33.1	42.8	33.9	43.5
Scenario 2 - Annual Energy Generation (Net): 230.3 GW·h				
17 335	13.7	16.7	14.4	17.3
26 055	18.0	22.4	18.6	23.1
34 272	22.0	27.8	22.6	28.5
50 738	30.0	38.6	30.6	39.3

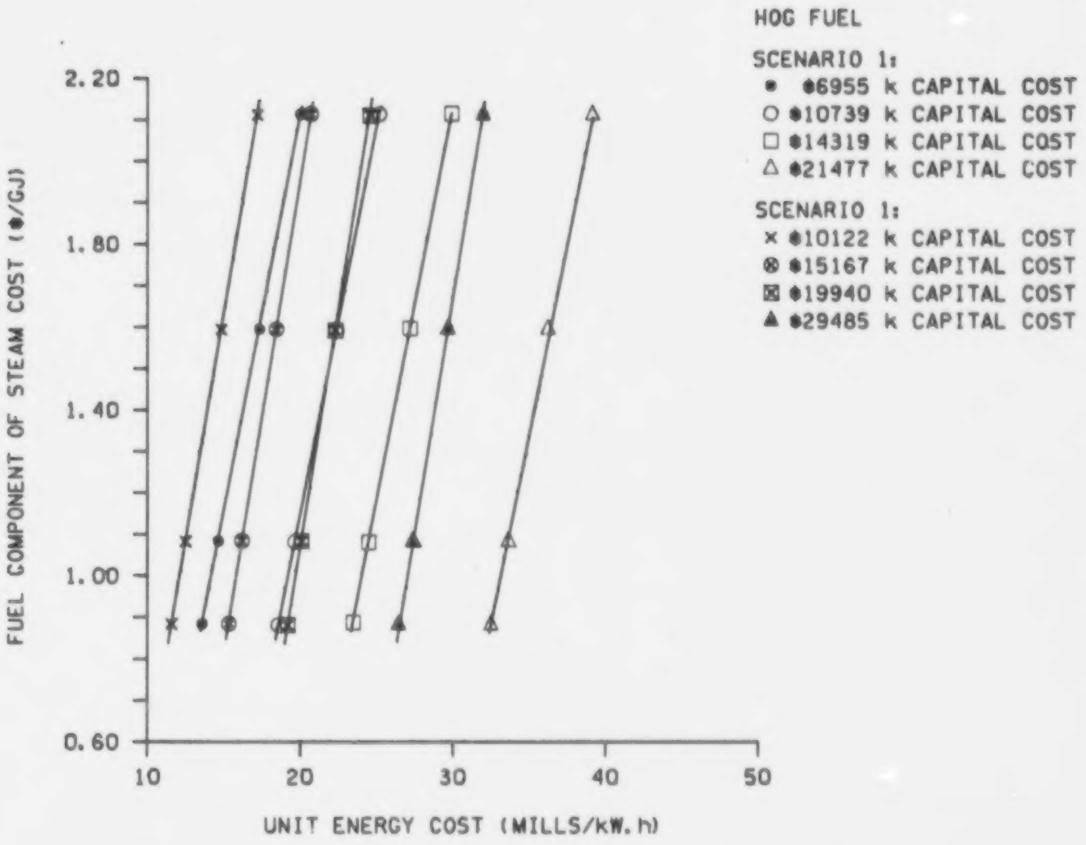

Figure 12 - 26

UNIT ENERGY COST - SCENARIOS 1 AND 2 - 4240 kPa/400°C

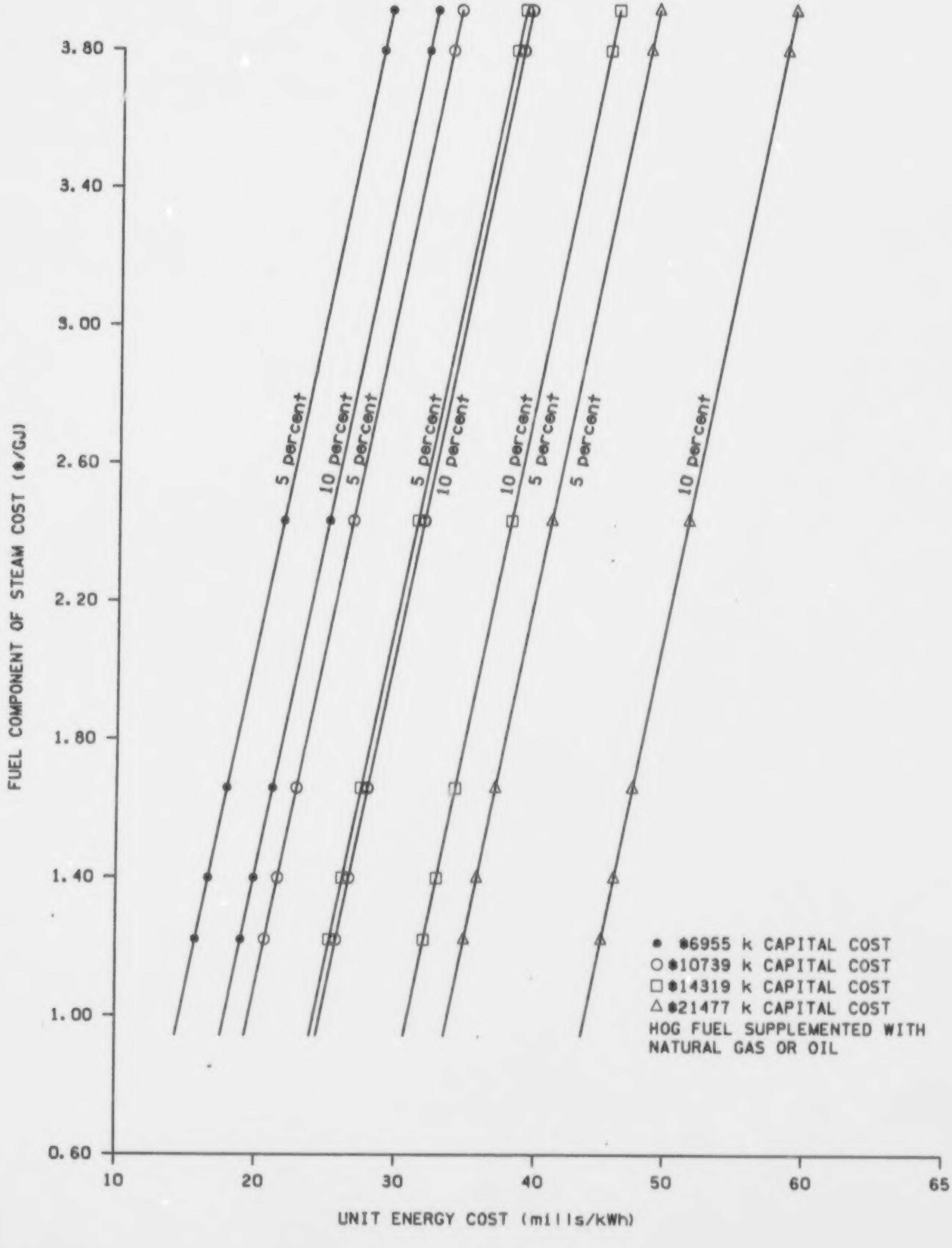

Figure 12 - 27

UNIT ENERGY COST - SCENARIO 1 - 4240 kPa/400° C

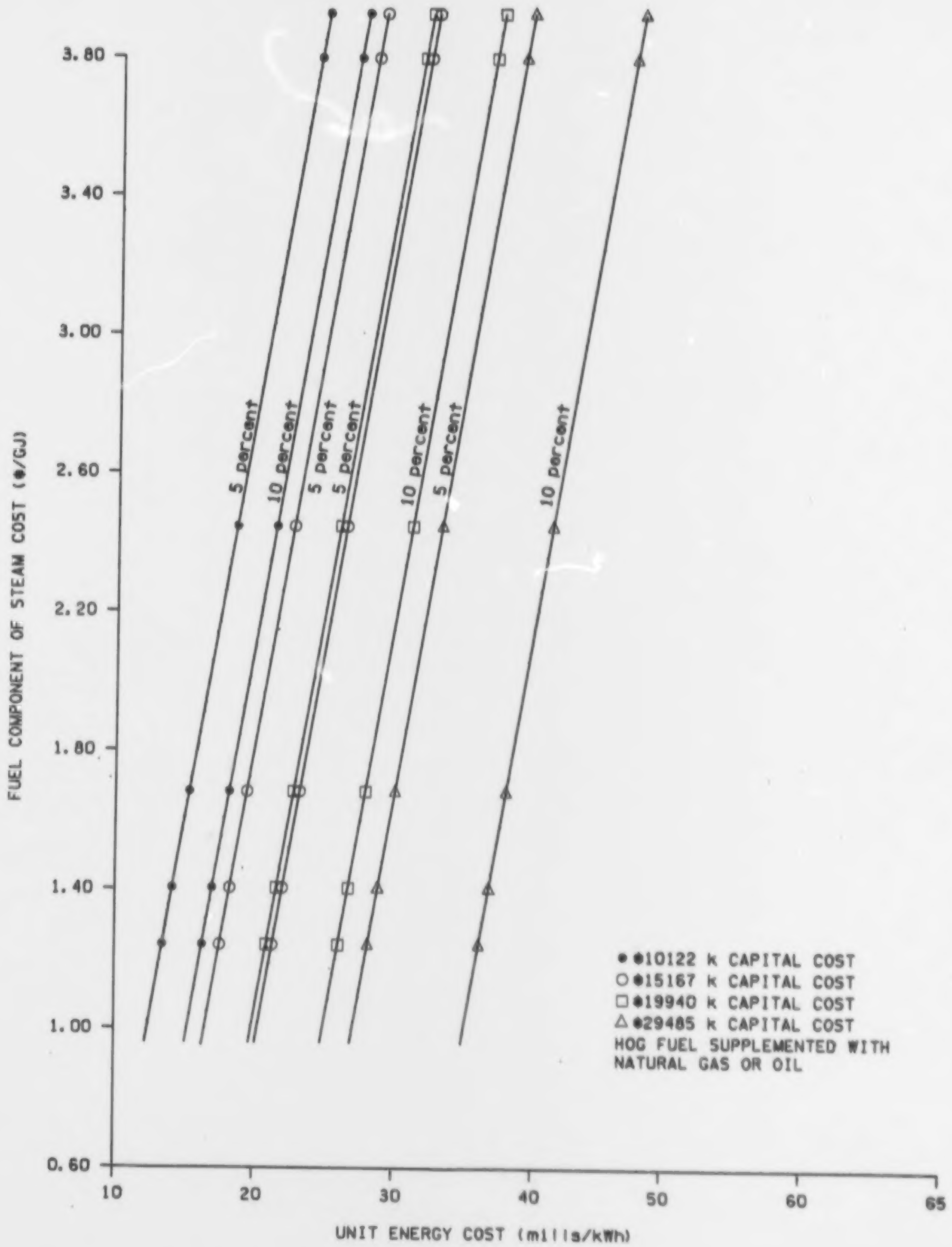

Figure 12 - 28

UNIT ENERGY COST - SCENARIO 2 - 4240 kPa/400° C

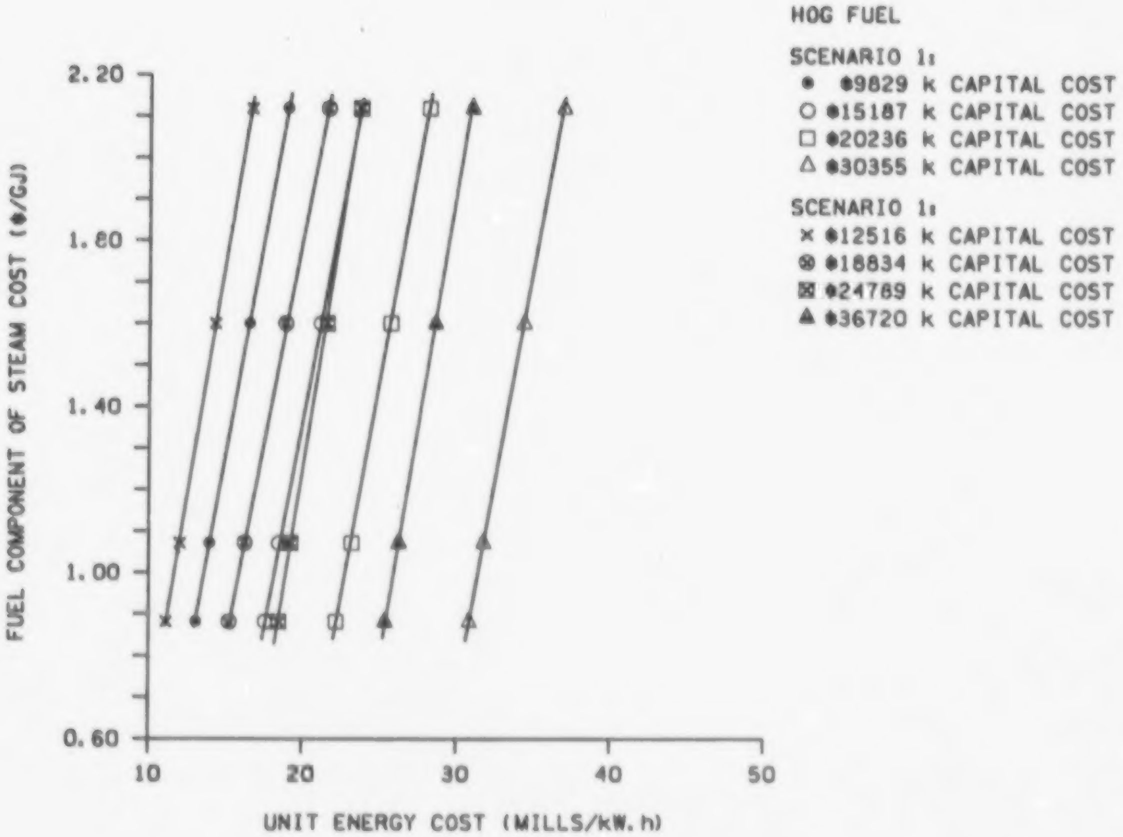

Figure 12 - 29

UNIT ENERGY COST - SCENARIOS 1 AND 2 - 6310 kPa/445°C

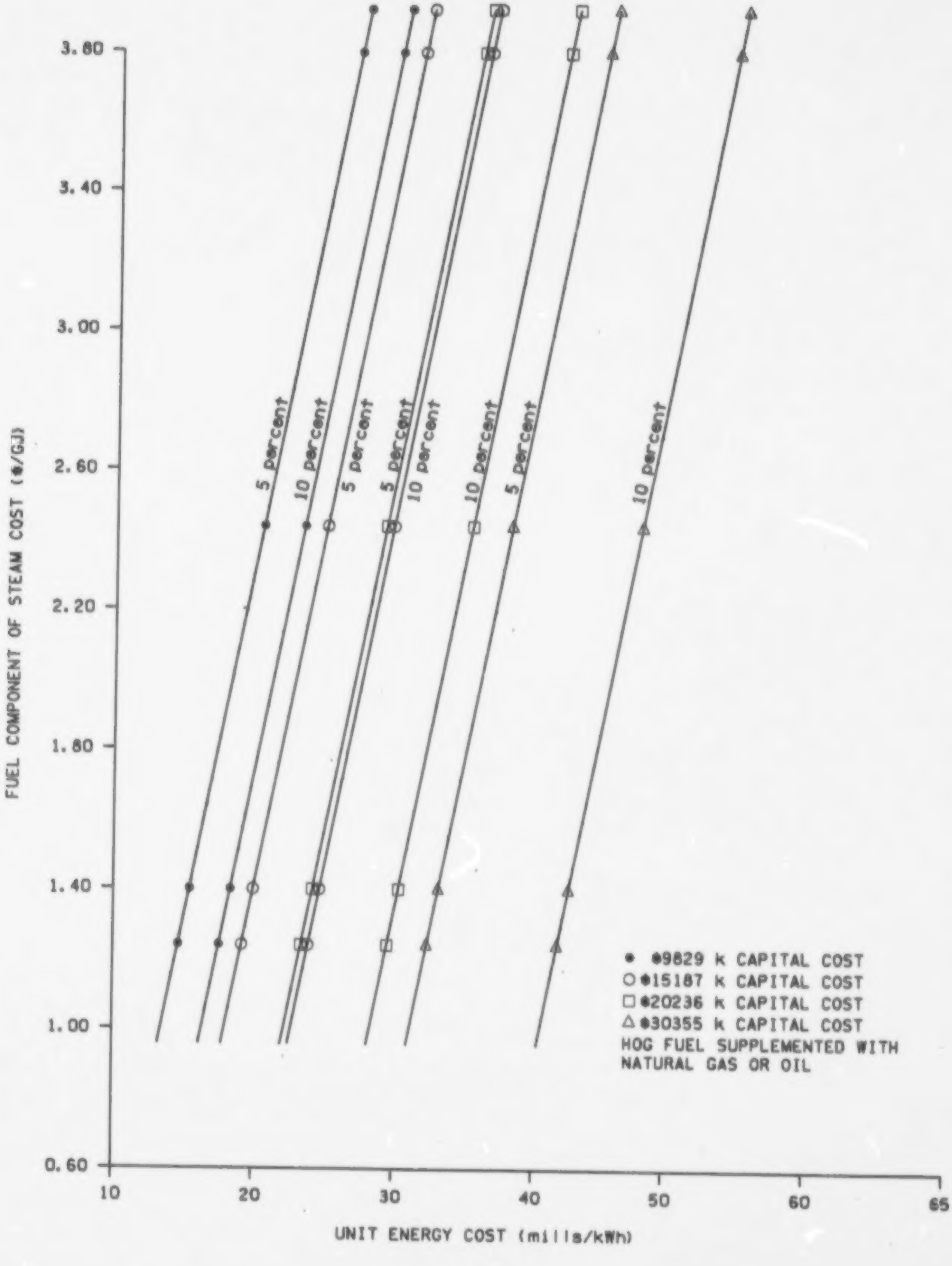

Figure 12 - 30

UNIT ENERGY COST - SCENARIO 1 - 6310 kPa/445° C

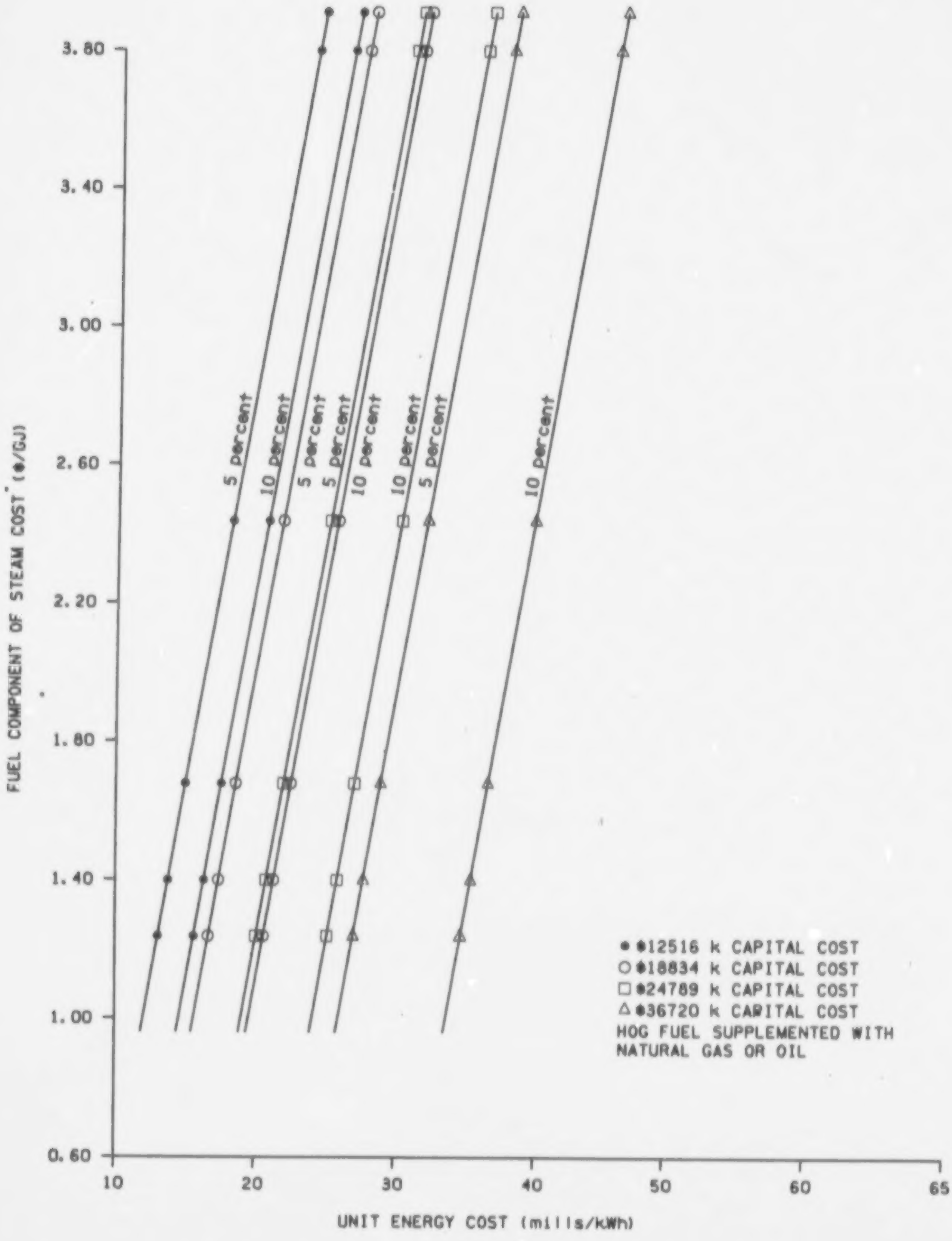

Figure 12 - 31

UNIT ENERGY COST - SCENARIO 2 - 6310 kPa/445° C

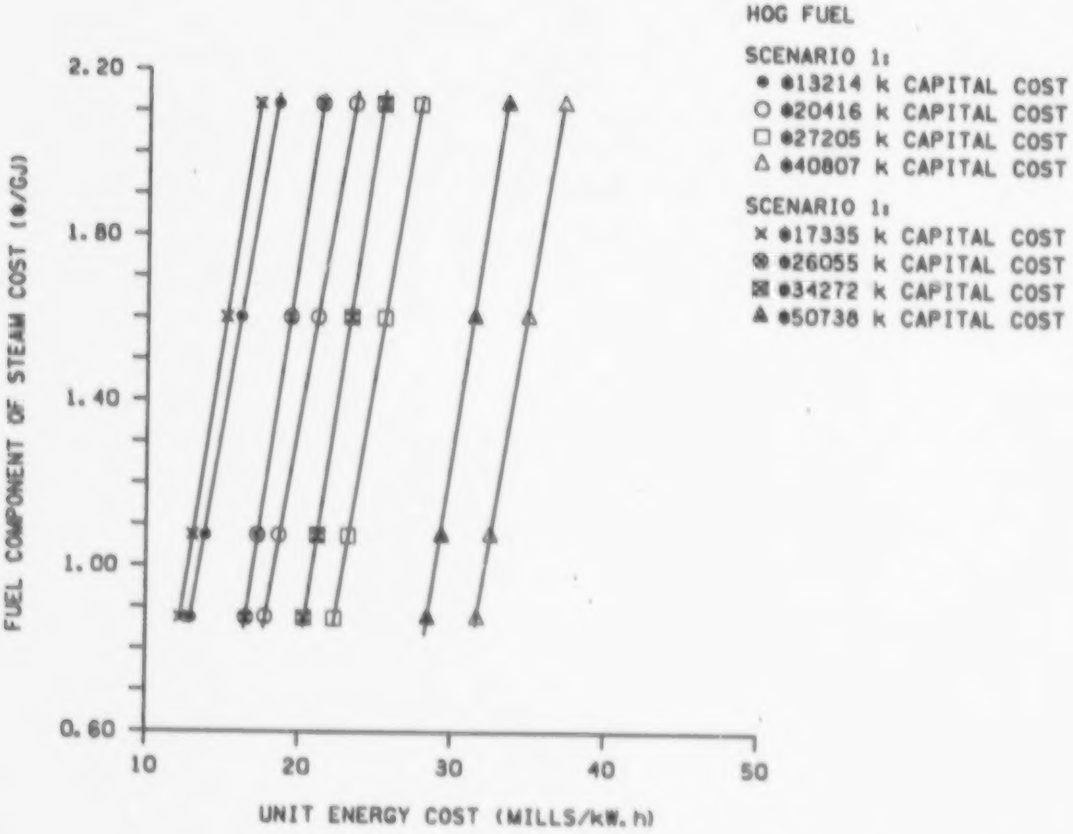

Figure 12 - 32

UNIT ENERGY COST - SCENARIOS 1 AND 2 - 8720 kPa/480°C

12.6 COGENERATION OPPORTUNITIES OUTSIDE THE PULP AND PAPER INDUSTRY

(a) Introduction

Most of the cogeneration opportunities in B.C. are in the pulp and paper sector of the forest industry. This sector uses large quantities of process heat and electricity. However, new technologies described in this report are reducing the demand for process heat and increasing the demand for electricity.

Many other industries could benefit from implementing cogeneration projects. Potentially, industries with electric demand/displaceable heat (electricity/heat) energy ratios between 0.3 and 0.6 are candidates for cogeneration.[78] Tables 12-29 and 12-30 list the electricity to heat ratios for California industries. Candidate industries for cogeneration include clothing, wood products, furniture, primary metal and fabricated metal industries. Industries with electric demand/displaceable heat ratios of less than 0.3 require additional heat from other sources and industries with ratios of more than 0.6 require additional electricity from the utility.

Industries with electricity and heat loads which complement each other could be combined at the same industrial complex. Those with surplus electricity (i.e. electric demand/displaceable heat ratio of <0.3) could also sell surplus electricity to a utility. Industries with high electricity demand and low heat demand are unlikely candidates for cogeneration. There is seldom an adjacent customer for the surplus heat.

Short operating seasons create another problem, making it difficult to achieve an acceptable rate-of-return. This is the situation in the processing of fruits and vegetables.

The petroleum industry has a high heat demand and this energy is often provided by by-product fuels; the industry also has the benefit of a nearly constant electricity and thermal demand. The thermal demand consists of direct heat and steam uses in a ratio of 4 to 1. High temperature processes require direct heat, whereas lower temperature processes can use steam. The electricity demand of a refinery could be met with a cogeneration system which would probably have surplus electricity for sale to a utility.

Over 90 percent of the energy used by the stone, clay and glass industries is in the form of high temperature direct heat. A bottoming cycle cogeneration system could be suitable for these industries.

TABLE 12-29

B.C. HYDRO INDUSTRIAL COMMERCIAL AND INSTITUTIONAL CUSTOMERS WITH A BASELINE PEAK DEMAND OF 200 kW TO 5000 kW

Standard Industrial Classification	Electric SIC Code	Electric/ Demand To Displaceable Heat Ratio[*1]	Hours of Operation	Minimum Demand (MW)	Maximum Demand (MW)	Annual Energy (GW·h)
Agriculture	110-210	-	-	0.20	0.89	1.71
Wood Product/Forestry	(310-320 (2511-2610	0.36	24	0.89	6.64	1565.39
Primary Metal/Nonmetal Mines	(510,710 (2910-2970 (3510-3590	0.30	24	0.87	14.67	198.20
Mineral Fuels	(611-620 3690	0.14	24	0.49	3.56	48.90
Food and Beverage	(410 (1010-1090	0.16	24	3.58	19.56	263.11
Tobacco	1520	-	-	0.25	0.25	1.20
Clothing	2430-2490	0.28-0.58	-	0.21	0.37	3.08
Paper Products	2711-2730	0.18	24	0.24	3.26	50.09
Commercial Printing	2860-2890	0.77	24	-	-	-
Metal Fabricating	3020-3090	0.30	24	0.20	3.79	104.58
Transport Equipment	3210-3280	1.02	24	0.21	2.97	36.16
Electrical	3310-3390	1.26	24	0.24	1.63	37.83
Chemical	3720-3760	0.22	24	0.25	2.02	19.94
Manufacturing	3910-3990	-	24	0.21	0.48	2.16
Construction	4110-4210	-	-	0.21	0.48	6.73
Transportation	5010-5110	-	-	0.24	1.15	13.33
Communications	5430-5450	-	-	-	-	-
Utilities	5740-5790	-	-	0.21	0.83	23.89
Business/Trade	(6020-6590 (8510-8690	0.6-4.3	12	0.61	9.41	698.49
Finance/Insurance	7020-7770	1.7	10	0.41	6.48	778.02
Hospitals	8210	0.5	24	-	-	-
Health/Recreation	8250-8410	0.5-1.7	10-24	0.48	3.13	88.85
Office Buildings/Schools	(7570-7580 (8020-8030 (8040-8070 (9020-9090 (9310	0.6-1.7	8-12	-	-	-
Shopping Centres	7670	4.3	12	-	-	-
Hotels/Apartments	(7450-7480 (8810-8830	0.6	24	- -	- -	- -
Amusement/Recreation	8410-8090	4.3	12	-	-	-
Laundries/Cleaners	8740	-	-	-	-	-

[*1] Based on California industries which would have higher air conditioning loads and lower heating loads than B.C. industries. The units are MW/10^6 Btu/h.

TABLE 12-30

B.C. HYDRO INDUSTRIAL, COMMERCIAL AND INSTITUTIONAL CUSTOMERS WITH A BASELINE PEAK DEMAND OF MORE THAN 5000 KW

Standard Industrial Classification	Electrical SIC Code	Electric Demand To Displaceable Heat Ratio[*1]	Hours of Operation	Minimum Demand (MW)	Maximum Demand (MW)	Annual Energy (GW·h)
Primary Metal/Nonmetal Mines	(510,710 (2910-2970 (3510-3590	0.30	24	42.74	54.52	420.62
Mineral Fuels	612-630	0.14	24	7.04	114.38	3131.27
Wood Product	2512-2520	0.36	24	5.04	11.35	413.70
Paper Products	2711	0.18	24	7.51	214.47	4747.27
Construction	4110	-	-	5.95	5.95	20.54
Business	8530	0.6-4.3	12	5.28	30.98	252.80
Insurance	7533-7539	1.7	10	5.09	8.18	117.98
Health/Welfare	8250	0.5-1.7	10-24	5.42	5.42	21.15

[*1] Based on California industries which would have higher air conditioning loads and lower heating loads than B.C. industries. The units are MW/10^6 Btu/h.

In examining cogeneration in industries which are outside the pulp and paper sector, twelve examples were evaluated to represent a range of generation alternatives:

1. Coal-fired thermal (6.14 MW).
2. Wood-fired thermal (25.0 MW)
3. Wood gasification gas turbine (1.34 MW).
4. Gas turbine (3.0 MW).
5. Gas turbine (0.8 MW).
6. Gas turbine (2.0 MW).
7. Gas turbine (4.0 MW).
8. Gas turbine (15.0 MW).
9. Gas turbine combined cycle (3.49 MW).
10. Gas turbine combined cycle (25.0 MW-@ 40 mills/kW·h).
11. Gas turbine combined cycle (25.0 MW-@ 35 mills/kW·h).
12. Internal combustion engine (6.9 MW).

The first is a bottoming cycle and the remainder are topping cycles.

(b) Bottoming Cycle Coal-Fired Thermal (6.14 MW)

A preliminary cost estimate was prepared for a 6.14 MW (net) bottoming cycle coal-fired thermal plant.[79] The cost information is summarized in Table 12-31. The fuel cost assumes mine site use of the coal. The efficiency of the system is assumed to be 40 percent thermal and 3.6 percent electrical for a total of 43.6 percent. The estimates of IRR, simple payback and unit energy cost are summarized in Table 12-32. Even assuming 40 mills/kW·h for the value of electricity, the initial investment would not be recovered within 25 years. The unit energy cost at a 5 percent (net) interest rate is estimated to be 48.6 mills/kW·h, well above the long-term marginal cost of energy at 35 mills/kW·h.

(c) Wood-Fired Thermal (25 MW)

The preliminary cost estimate for a 25 MW (net) wood-fired thermal cogeneration plant is based on estimates by Simons Resource Consultants/B. H. Levelton and Associates[80] and Shawinigan Integ.[81] The cost information is summarized in Table 12-33. The fuel cost is based on Interior B.C. hog fuel with supplementary natural gas. The efficiency of the system is

TABLE 12-31

BOTTOMING CYCLE COAL-FIRED THERMAL COGENERATION PLANT (6.14 MW) PRELIMINARY COST ESTIMATE

Capital Cost	$12,080,000 ($1968/kW)
Plant Capacity (Net)	6.14 MW
Construction Time	1 year
Plant Life	25 years
Electricity Generation (80% C.F.)	43 GW·h
Fuel Cost (Coal)	$1.30/GJ
Heat Rate	99 617 kJ/kW·h
Annual Operating and Maintenance Cost (@ 6.98 percent of capital cost)[*1,*2]	$843,000
Annual Process Steam Credit[*1,*2]	$5,179,553

[*1] All annual costs were inflated at 5 %/a when estimating IRR and payback period.

[*2] Based on 1 713 417 GJ/a from process steam at a cost of 162 kg/$1.00 and a recoverable heat rate of 2040 kJ/kg for steam at 1135 kPa/196°C (i.e. approximately $3.02/GJ).

TABLE 12-32

ECONOMIC ANALYSIS OF COGENERATION OPPORTUNITIES OUTSIDE THE PULP AND PAPER INDUSTRY

Cogeneration System	Capacity (MW)	After Tax Internal[*1] Rate of Return (%)	Simple Payback[*1] After Tax (Years)	Unit Energy Cost (mills/kW·h) 5% - Discount Rate-10%	
Bottoming Cycle	6.14	1.1	>25	48.6	59.6
Topping Cycles:					
Wood-Fired Thermal	25.0	17.9	5.3	6.5	19.2
Wood Gasification Gas Turbine	1.34	10.6	9.1	34.5	44.7
Gas Turbine	3.0	6.5	13.2	42.6	52.5
Gas Turbine	0.8	12.2	8.0	31.3	37.1
Gas Turbine	2.0	29.2	3.0	4.9	10.2
Gas Turbine	4.0	19.1	4.9	27.9	31.7
Gas Turbine	15.0	10.4	9.3	39.6	44.6
Gas Turbine Combined Cycle	3.49	6.6	13.1	42.0	51.9
Gas Turbine Combined Cycle	25.0	23.6	3.8	22.0	26.0
Gas Turbine Combined Cycle	25.0	20.0[*2]	4.7	22.0	26.0
Internal Combustion Engine	6.9	16.8	6.7	29.4	34.3
Internal Combustion Engine	6.9	13.5[*2]	7.3	29.4	34.3

[*1] Assuming the value of electricity is 40 mills/kW·h.

[*2] Assuming the value of electricity is 35 mills/kW·h.

TABLE 12-33

WOOD-FIRED THERMAL COGENERATION PLANT (25 MW)
PRELIMINARY COST ESTIMATE

Capital Cost	$56,307,000 ($2252/kW)
Plant Capacity (Net)	25 MW
Construction Time	1 year
Plant Life	25 years
Electricity Generation (80% C.F.)	175 GW·h
Fuel Cost Component of Steam Cost (based on hog fuel with supplementary natural gas)[*1,*2]	$1.25/GJ
Heat Rate	32 925 kJ/kW·h
Annual Operating and Maintenance Cost (@ 4.96 percent of capital cost)[*2]	$2,791,000/a
Annual Process Steam Credit[*2,*3]	$12,838,230/a

[*1] Assumes 85 percent wood at $0.71/GJ and 15 percent natural gas @ $1.80/GJ, each corrected for respective boiler efficiencies.

[*2] All annual costs were inflated by 5 %/a when estimating IRR and payback period.

[*3] Based on 4 246 938 GJ/a from process steam at a cost of 162 kg/$1.00 and a recoverable heat rate of 2042 kJ/kg for steam at 1135 kPa/196°C (i.e. approximately $3.02/GJ).

assumed to be 51.3 percent thermal and 10.7 percent electrical for an overall efficiency of 62 percent. The estimates of IRR, simple payback and unit energy cost are summarized in Table 12-32. At 40 mills/kW·h for electricity, the initial investment would be recovered in 5.3 years. However, the internal rate of return would be only 17.9 percent which is below the 20 percent hurdle rate. The unit energy cost for electricity at a 5 percent (net) interest rate is estimated to be 6.5 mills/kW·h, well below the long-term marginal cost of energy at 35 mills/kW·h. The reason the unit energy cost is exceptionally low is the high value placed on steam which offsets most of the cost of capital and operation. In this estimate none of the benefits of the inexpensive wood fuel are credited to the steam, they are all credited to electricity generation. If the capital and operating costs are apportioned between electricity and process steam generation relative to the respective efficiencies the cost of electricity would be 45.3 mills/kW·h, well above the long-term marginal cost of energy.

(d) Wood Gasification Gas Turbine (1.34 MW)

The preliminary cost estimate for a 1.34 MW (net) wood gasification/gas turbine cogeneration plant is based on a cost estimate by Canadian Resourcecon.[47] The cost information is summarized in Table 12-34. The fuel cost assumes the hog fuel is self-produced at an Interior B.C. location. The efficiency of the system is assumed to be 36 percent thermal and 17 percent electrical for a total of 53 percent. The estimates for the IRR, simple payback and unit energy cost are summarized in Table 12-32. Assuming the value of electricity is 40 mills/kW·h the initial investment would be recovered in 9.1 years. The unit energy cost at 5 percent (net) interest rate is estimated to be 34.5 mills/kW·h, approximately equivalent to the long-term marginal cost at 35 mills/kW·h.

(e) Gas Turbines (800 kW-4 MW)

The preliminary cost estimate for a 3 MW (net) gas turbine cogeneration plant is based on a cost estimate by Miller et al.[78] The cost information is summarized in Table 12-35. The efficiency of the system is assumed to be 40 percent thermal and 24 percent electrical for a total of 64 percent. The estimates for IRR, simple payback and unit energy cost are summarized in Table 12-32. Even at 40 mills/kW·h for electricity it would require 13.2 years to recover the initial investment. The after tax internal rate of return would be only 6.5 percent, well below the 20 percent hurdle rate. The unit energy cost at a 5 percent net interest rate is estimated to be 42.6 mills/kW·h, well above the long-term marginal cost of energy at 35 mills/kW·h.

Specific applications of other small gas turbine cogeneration systems were examined in a report by Ismail et al (1987).[82] These applications consist of an 800 kW system, operating in parallel with a diesel generating plant at an off-grid mine, a

TABLE 12-34

WOOD GASIFICATION GAS TURBINE COGENERATION PLANT (1.34 MW)
PRELIMINARY COST ESTIMATE

Capital Cost	$2,445,000 ($1825/kW)
Plant Capacity (Net)	1.34 MW
Construction Time	1 year
Plant Life	25 years
Electricity Generation (80% C.F.)	9.4 GW·h
Fuel Cost (Hog Fuel)	$0.71/GJ
Heat Rate	21 664 kJ/kW·h
Annual Operating and Maintenance Cost (@ 9.40 percent of capital cost)[*1]	$376,030
Annual Process Steam Credit[*1,*2]	$223,210

[*1] All annual costs were inflated at 5 %/a when estimating IRR and payback period.

[*2] Based on 73 836 GJ/a from process steam at a cost of 162 kg/$1.00 and a recoverable heat rate of 2042 kJ/kg for steam at 1135 kPa/196°C.

TABLE 12-35

GAS TURBINE COGENERATION PLANT (3 MW) PRELIMINARY COST ESTIMATE

Capital Cost	$5,284,000 ($1761/kW)
Plant Capacity (Net)	3 MW
Construction Time	1 year
Plant Life	25 years
Electricity Generation (80% C.F.)	21 GW·h
Fuel Cost (Natural Gas)[*1]	$1.80/GJ
Heat Rate	14 771 kJ/kW·h
Annual Operating and Maintenance Cost (@ 6.38 percent of capital cost)[*1]	$337,287
Annual Process Steam Credit[*2]	$375,075

[*1] All annual costs were inflated by 5 %/a when estimating IRR and payback period.

[*2] Based on 124 076 GJ/a from process steam at a cost of 162 kg/$1.00 and a recoverable heat rate of 2042 kJ/kg for steam at 1135 kPa/196°C.

2 MW gas turbine at a food processing plant and a 4 MW gas turbine at a chemical plant, each operating in parallel with a utility system. The steam estimates and costs from these applications were modified to suit the B.C. situation and to maximize the use of the energy from these cogeneration systems.

The 800 kW (815 kW average capacity) gas turbine is assumed to have a heat recovery boiler and is designed for base loading.[82] Low pressure steam from the heat recovery boiler is used for ore processing and space heating. Cost information on this system is summarized in Table 12-36. The fuel cost is based on the use of diesel fuel. The efficiency of the system is assumed to be 44.9 percent thermal and 26 percent electrical for an overall efficiency of 70.9 percent. The estimates of IRR, simple payback and unit energy cost are summarized in Table 12-32. At 40 mills/kW·h for electricity the initial investment would be recovered at 8.0 years. The after tax internal rate of return would be 12.2 percent, well below the 20 percent hurdle rate. However, the unit energy cost at a 5 percent (net interest rate) would be only 31.3 mills/kW·h which could make the system economic to some investors.

Production in the food processing industry can be seasonal or continuous depending on the product(s) and market demand. A case history described in Ismail et al (1987)[82] is based on a plant operating 3 shifts/day, five days/week, 12 months per year. During food production, electrical demand peaks at 4.1 MW, but decreases to 1.5 MW on weekends. Steam demand peaks at over 11 340 kg/h (25 000 lb/h), but decreases to 5440 kg/h (12 000 lb/h) on weekends. A 2 MW gas turbine cogeneration set was assumed for this application. The set consists of a gas turbine-generator set and a heat recovery boiler similar to that outlined in the schematic in Section 10.5 (Figure 10-6). The gas turbine-generator set could be used to provide the base load and peaking power could be purchased from the utility.

Cost information is summarized in Table 12-37. The fuel cost assumes the use of natural gas. The efficiency of the system is assumed to be 50.0 percent thermal and 27.3 percent electrical for an overall efficiency of 77.3 percent. The estimates of IRR, simple payback and unit energy cost are summarized in Table 12-32. At 40 mills/kW·h for electricity the initial investment would be recovered in 3 years and the internal rate of return is estimated to be 29.2 percent, well above the 20 percent hurdle rate. The unit energy cost would be only 4.9 mills/kW·h. These estimates are particularly favorable because of the high efficiency and a large steam credit based on a high value for steam which was assumed in the study by Ismail et al (1987).[82]

A chemical plant with an average electricity demand of 7.8 MW and a 4 MW gas turbine cogeneration system was used as another example. Energy would be recovered from the exhaust gases to produce 200 psig (1480 kPa) steam. The system would be operated 3 shifts/day, 7 days/week, 12 months per year. Cost information

TABLE 12-36

GAS TURBINE COGENERATION PLANT (800 kW) PRELIMINARY COST ESTIMATE

Capital Cost	$828,345 ($1035/kW)
Plant Capacity (Net)	800 kW
Construction Time	1 year
Plant Life	25 years
Electricity Generation (80% C.F.)	5.60 GW·h
Fuel Cost (Diesel)*1	$5.50/GJ
Heat Rate	13 845 kJ/kW·h
Annual Operating and Maintenance Cost (@ 4.03 percent of capital cost)*1	$33,380
Annual Process Steam Credit*2	$343,425

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*1 All annual costs were inflated by 5 %/a when estimating IRR and payback period.

*2 Based on recovery of 34 828 GJ of process steam and space heat valued at $4.44/GJ.

TABLE 12-37

GAS TURBINE COGENERATION PLANT (2 MW) FOR A FOOD PROCESSING FACILITY - PRELIMINARY COST ESTIMATE

Capital Cost	$1,875,930 ($938/kW)
Plant Capacity (Net)	2 MW
Construction Time	1 year
Plant Life	25 years
Electricity Generation (80% C.F.)	14.0 GW·h
Fuel Cost (Natural Gas)	$1.80/GJ
Heat Rate	13 200 kJ/kW·h
Annual Operating and Maintenance Cost (@ 2.32 percent of capital cost)	$43,522
Annual Process Steam Credit	$440,339

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*1 Annual costs are uninflated costs. All annual costs were inflated by 5 %/a when estimating IRR and payback period.

*2 Based on a heat recovery of 92 400 GJ of process steam valued at $4.77/GJ.

on this system is summarized in Table 12-38. The fuel cost is based on using natural gas. The efficiency of the system is assumed to be 45 percent thermal and 26.4 percent electrical for an overall efficiency of 71.4 percent. The estimates of IRR, simple payback and unit energy cost are summarized in Table 12-32. At 40 mills/kW·h for electricity the initial investment would be recovered in 4.9 years and the internal rate of return is estimated to be 19.1 percent, slightly below the hurdle rate of 20 percent. The unit energy cost for electricity at a 5 percent (net) interest rate would be 27.9 mills/kW·h, which is below the long-term marginal cost of electricity. Therefore, a small gas turbine cogeneration plant serving a chemical facility could be economical.

(f) Gas Turbine (15 MW)

The preliminary cost estimate for a 15 MW (net) gas turbine cogeneration plant is based on a cost estimate by Miller et al.[78] The cost information is summarized in Table 12-39. The efficiency of the system is assumed to be 42 percent thermal and 30 percent electrical for a total of 72 percent. The estimates for IRR, simple payback and unit energy cost are summarized in Table 12-32. The payback period is estimated to be 9.3 years with an after tax internal rate of return of only 10.4 percent, well below the 20 percent hurdle rate. These estimates optimistically assume a value of electricity of 40 mills/kW·h. The unit energy cost at a 5 percent (net) interest rate is estimated to be 39.6 mills/kW·h which is above the long-term marginal cost of 35 mills/kW·h. The difference between the economics of this system and the one described for a chemical plant is the value of the process steam. A high steam credit could make this project economical.

(g) Gas Turbine Combined Cycle (3.49 MW)

The preliminary cost estimate for a 3.49 MW (net) gas turbine combined cycle cogeneration plant is based on a cost estimate by RMR Associates.[79] The cost information is summarized in Table 12-40. The cost estimate assumes the use of a combustion turbine with heat recovery and supplementary firing, an extraction steam turbine and a condenser. The estimates for IRR, simple payback and unit energy cost are summarized in Table 12-32. The payback for a 3.49 MW gas turbine combined cycle cogeneration plant is estimated to be 13 years and the after tax internal rate of return is estimated to be 6.6 percent, which is well below the 20 percent hurdle rate. The unit energy cost at a 5 percent (net) interest rate is estimated to be 42 mills/kW·h, well above the long-term marginal cost at 35 mills/kW·h.

TABLE 12-38

GAS TURBINE COGENERATION PLANT (4 MW) AT A CHEMICAL PLANT - PRELIMINARY COST ESTIMATE

Capital Cost	$2,685,700 ($671/kW)
Plant Capacity (Net)	4 MW
Construction Time	1 year
Plant Life	25 years
Electricity Generation (80% C.F.)	28.0 GW·h
Fuel Cost (Natural Gas)	$1.80/GJ
Heat Rate	13 655 kJ/kW·h
Annual Operating and Maintenance Cost (@ 2.79 percent of capital cost)[*1]	$74,930
Annual Process Steam Credit	$172,055

[*1] Annual cost are uninflated costs. All annual costs are inflated by 5 %/a when estimating IRR and payback period.

[*2] Based on 172 055 GJ/a of process steam at a cost of $3.85/GJ.

TABLE 12-39

GAS TURBINE COGENERATION PLANT (15 MW)
PRELIMINARY COST ESTIMATE

Capital Cost	$24,322,000 ($1621/kW)
Plant Capacity (Net)	15 MW
Construction Time	1 year
Plant Life	25 years
Electricity Generation (80% C.F.)	105 GW·h
Fuel Cost (Natural Gas)[*1]	$1.80/GJ
Heat Rate	12 133 kJ/kW·h
Annual Operating and Maintenance Cost (@ 5.36 percent of capital cost)[*1]	$1,303,660
Annual Process Steam Credit[*2]	$1,617,000

[*1] All annual costs were inflated by 5 %/a when estimating IRR and payback period.

[*2] Based on 124 076 GJ/a of process steam at a cost of 162 kg/$1.00 and a recoverable heat rate of 2042 kJ/kg of steam at 1135 kPa/196°C (i.e. approximately $3.02/GJ).

TABLE 12-40

GAS TURBINE COMBINED CYCLE COGENERATION PLANT (3.49 kW)
PRELIMINARY COST ESTIMATE

Capital Cost	$6,147,00 ($1762/kW)
Plant Capacity (Net)	3.49 MW
Construction Time	1 year
Plant Life	25 years
Electricity Generation (80% C.F.)	24.42 GW·h
Fuel Cost (Natural Gas)[*1]	$1.80/GJ
Heat Rate	19 287 kJ/kW·h
Annual Operating and Maintenance Cost (@ 5.08 percent of capital cost)[*1]	$312,000
Annual Process Steam Credit[*1,*2]	$569,522

[*1] All annual costs were inflated by 5 %/a when estimating IRR and payback period.

[*2] Based on 188,400 GJ/a from process steam at a cost of 162 kg/$1.00 and a recoverable heat rate of 2042 kJ/kg of steam at 1135 kPa/196°C.

(h) Gas Turbine Combined Cycle (25 MW)

The preliminary cost estimate for a 25 MW (net) gas turbine combined cycle cogeneration plant is based on information in Kehlhofer (1987)[83] and Shawinigan Integ (1987).[81] The cost information is summarized in Table 12-41. The cost estimate consists of the plant capital and the operating and maintenance cost attributable to electricity generation. The efficiency of the system was assumed to be 38 percent thermal and 37 percent electrical for a total of 75 percent. The estimate for IRR, simple payback and unit energy cost are summarized in Table 12-32. The IRR and simple payback are estimated for two values of electricity:35 and 40 mills/kW•h. The payback for a 25 MW gas turbine combined cycle plant ranges 3.8 to 4.7 years and the IRR ranges from 20.0 to 23.6 percent depending on the value of electricity. The unit energy cost is 22 mills/kW•h at a 5 percent (net) interest rate. Clearly, a gas turbine combined cycle plant with a low natural gas price could be economical assuming high heat recovery.

(i) Internal Combustion Engine (6.9 MW)

The preliminary cost estimate for a 6.9 MW (net) internal combustion engine cogeneration plant is based on cost estimates by North (1984)[84] and RMR Associates (1986).[79] The report by North (1984) describes a proposal to convert the Cooper Bessemer LSV-16 units at the Fort Nelson Diesel Generating Station (D.G.S.) to cogeneration by using the jacket water as a source of heat.

The Cooper Bessemer LSV-16 units at Fort Nelson are approximately 33 percent efficient in converting the energy of natural gas/diesel oil to electricity. With an electric load of 2.1 MW, a typical energy balance for a single unit based on the 1983 capacity factor would be as follows:

Units	Fuel Input		Electricity Output		Exhaust Losses		Jacket Water Losses		Lube Oil After Cooler Losses		Radiation Losses
%	100	=	33	+	25	+	22	+	10	+	10
MW•h	6.3	=	2.1	+	1.6	+	1.4	+	0.6	+	0.6
GJ	22.7	=	7.6	+	5.7	+	5.0	+	2.2	+	2.2

The exhaust and jacket water are the only waste heat sources amenable to waste heat recovery. Nearly 100 percent of jacket water heat and 50 percent of the exhaust heat are recoverable. Exhaust heat recovery is limited because the exhaust gases must be kept above the dew point temperature (149°C - 177°C) to minimize corrosion in the exhaust system. The low temperature and small quantity of heat available from the lube oil/after cooler circuit make recovery of this heat unattractive. Much of

TABLE 12-41

GAS TURBINE COMBINED CYCLE COGENERATION PLANT (25 MW) PRELIMINARY COST ESTIMATE

Capital Cost[*1]	$17,854,000 ($714/kW)
Plant Capacity	25 MW
Construction Time	1 year
Plant Life	25 years
Electricity Generation (80% C.F.)	175.2 GW·h
Fuel Cost (Natural Gas)[*2]	$1.80/GJ
Heat Rate	4800 kJ/kW·h
Annual Operating and Maintenance Cost (@ 5.98 percent of capital cost)[*2]	$1,068,000

[*1] Electricity generation component of plant capital cost (approximately 70 percent of plant cost).

[*2] All annual costs were inflated by 5 %/a when estimating IRR and payback period.

the heat from radiation is trapped inside the powerhouse and partly heats the building in winter.

A hot water recovery system offers a simple, economical method for recovering heat from diesel generating systems such as the one at Fort Nelson. The system could use 50/50 glycol/water as the transport medium for space and hot water heating. A shell and tube heat exchanger could be used to recover jacket water heat with a shell and tube heat recovery exhaust silencer for recovering exhaust heat. In the Fort Nelson plant, an 8 inch (20.3 cm) diameter piping system with a flow rate of 1000 gpm (4540 l/min) would be expected to provide hot water from the three units at a temperature of 54 to 60°C.

A cost estimate for a hot water recovery system for the 3 Cooper Bessemer LSV-16 units at the Fort Nelson Diesel Generating Station is summarized in Table 12-42. The cost estimate is for jacket water heat recovery only.

A preliminary cost estimate for a diesel generating station without heat recovery is included in Table 12-43 in order to complement the estimate for a heat recovery system and provide information on the cost of a diesel cogeneration plant.

The results of the economic analysis are summarized in Table 12-32. For an electricity price of 40 mills/kW·h the payback for a 6.9 MW internal combustion engine cogeneration system with jacket water heat recovery is estimated to be 6.7 years and the after tax internal rate of return is estimated to be 16.8 percent, which is well below the 20 percent hurdle rate. The unit energy cost at a 5 percent (net) interest rate is estimated to be 29.4 mills/kW·h, which is below the long-term marginal cost of 35 mills/kW·h for the cost of generation on the main B.C. Hydro grid. However, in this estimate the value of the hot water for space heating was assumed to be the same as the value of steam for electricity generation which is unrealistically high. An economic analysis assuming an electricity price of 35 mills/kW·h is included for comparison.

(j) Discussion

Few of these alternative cogeneration opportunities are economical or even potentially economical at today's costs and electricity prices. However, under conditions of high steam costs and high values for electricity (40 mills/kW·h) gas turbine and gas turbine combined cycle power plants could be economical. Industries such as food processing and pulp and paper could use these generation technologies.

TABLE 12-42

CAPITAL COST OF HOT WATER RECOVERY FOR THE FORT NELSON DIESEL GENERATING STATION

Heat Exchangers (5)	$128,000
Amot Thermostatic Valves (5)	16,000
Miscellaneous Piping Material	87,000
1000 gal/min Pumps and Controls	12,000
Insulation	17,000
Insulation Labour	160,000
Miscellaneous	46,000
TOTAL	$466,000

TABLE 12-43

DIESEL GENERATING PLANT (6.9 MW)
PRELIMINARY COST ESTIMATE

Capital Cost*[1]	$6,384,000 ($925/kW)
Plant Capacity	6.9 MW
Construction Time	1 year
Plant Life	20 years
Electricity Generation (80% C.F.)	48.3 GW·h
Fuel Cost (Natural Gas and Diesel)	$1.99/GJ
Heat Rate*[2]	12 038 kJ/kW·h
Annual Operating and Maintenance Cost (@ 3.25 percent of capital cost)	$208,118

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*1 For electric generation only.

*2 Heat rate for electric generation only is 7261 kJ/kW·h.

SECTION 13.0 - FUTURE TECHNOLOGIES

There are several technologies being developed which could have applications in cogeneration. These technologies include the following:[67]

1. Organic Rankine turbines based on the steam turbine bottoming cycle, but with an organic substance as the working fluid and which could generate electricity from waste heat at temperatures as low as 93°C.

2. Sterling engines, similar to automobile engines, which compress and expand a gas in a cylinder to drive a crankshaft and have the potential to use alternate fuels at high efficiencies.

3. Fluidized bed combustion which burns fuel at moderate temperatures in a bed of ash and limestone; a variety of solid fuels could be burned without the use of flue gas desulphurization equipment.

4. Gasification which could produce fuel from coal or biomass for cogeneration topping cycles.

5. Fuel cells which are electrochemical devices that convert chemical energy directly into electricity without a combustion stage; they could be used to supplement electricity from cogeneration.

6. Cheng steam injection cycles which could be used to inject steam into a gas turbine and increase electricity output.

7. Kalina cycles which use an ammonia-water mixture in a bottoming cycle and when combined with a gas turbine or internal combustion engine could more closely match ideal heating and cooling curves thereby improving efficiency.

8. A split-fired boiler which has been proposed for firing hog fuel with a high percentage of sawdust;[87] the wet fuel is pre-dried by the flue gas to a moisture content of 45 to 50 percent and the dried fuel is screened to separate the fines; the fines are pulverized, flash dried and fired tangentially while the larger particles are simply distributed and fired on a furnace grate.

These technologies could improve the efficiency and/or versatility of cogeneration systems.

SECTION 14.0 - DISCUSSION

As previously noted, cogeneration is the sequential production of mechanical or electrical and useful thermal energy (process steam, heat and/or hot water) from a single energy source (fuel). Because of this sequential production, the efficiency of a cogeneration system is 40 to 85 percent compared with 15 to 40 percent for conventional thermal power generation.

From an industry perspective, cogeneration has certain attractions including increased energy efficiency, lower electricity costs, possible revenue from the sale of electricity to a utility and improved public relations. However, offsetting these potential benefits are higher capital cost, additional finance charges, possible difficulties in retrofitting, increased operation and maintenance costs and most important, the lost opportunity which could result from investing that money elsewhere, particularly in increasing production and presumably revenue.

Cogeneration or non-condensing generation requires that the process steam load and power production be balanced. Increased boiler steam pressures increase the relative amount of electric power that can be generated, thus all cogenerating plants operating at 4140 kPa (600 psig) could generate as much as 50 percent more power by modifying their boilers to 8600 kPa (1250 psig) operation.[19] However, this would require boiler and turbine generator replacement. At these pressures, many pulp and paper mills which require large amounts of process steam could produce a significant surplus of electricity. Newsprint mills and wood product mills, on the other hand, require appreciably more electrical power and would normally use all cogenerated power internally to reduce their electricity purchases. However, they have little use for cogeneration because of their small steam requirements unless integrated with a kraft pulp mill.

The pulp and paper industry in B.C. is capable of using additional electricity generation at high load factors. Most B.C. pulp mills produce high pressure steam at 4140 kPa (600 psig) or more which they pass through backpressure turbogenerators to produce electricity and supply plant process steam through a topping cycle. The process steam is generally at pressures of approximately 445 to 1340 kPa (50 to 150 psig). With cogeneration, the losses caused by pressure control and condensation are reduced. Therefore, energy conversion efficiencies can be as high as 60 to 80 percent. Condensing turbines could be used with hog fuel or recovery boilers, but the excess steam would be condensed and much of the energy wasted.

A 1980 study by Integ identified a potential for 225 MW of additional cogeneration which could be installed by the pulp and paper industry in B.C. Another 300 MW to 400 MW could be installed if high pressure/temperature boilers were used.[19.59]

Improvements in energy use and the development of self-generation (cogeneration) in the Canadian pulp and paper industry are indicative of the changes in B.C. There was a 27 percent decrease in purchased energy per unit of product between 1972 and 1984.[22] Between 1975 and 1984 the production of Canadian thermo-mechanical pulp increased from 620 t to 12 275 t/day (air dried) or 15 percent of total pulping capacity.[88,89] The growth in thermo-mechanical and chemi-thermo-mechanical pulping is continuing to increase electricity demand, conserve wood and reduce steam demand. Another change which is expected to be important in a few years is the use of recycled paper which requires significantly less energy for processing than other forms of pulp (Table 9-5). The driving force for this change is the limited availability of landfills. Therefore, changes in technology and product could significantly reduce potential increases in cogeneration in the pulp and paper industry.

Another study which also examined the potential for industrial steam turbine cogeneration in British Columbia was completed for EMR Canada in 1982.[88] The potential was divided into commercial (financially feasible assuming constant real electricity prices over the project life), and economic (economically feasible compared with the cost of supply from conventional power generation). The commercial potential for industrial steam turbine cogeneration was estimated to be 21 MW for natural gas fuel and 250 MW for wood waste fuel. The corresponding estimates for economic potential were 570 MW for natural gas fuel and 574 MW for wood waste fuel. Most of this potential was in the forest industry where studies for a total of 845 MW[*1] are underway or were completed recently. There is also the potential for 550 MW of cogeneration identified from other industries. Although it would be overly optimistic to expect to develop more than half of this potential in the near term, given today's economic climate and the low cost of fossil fuels, more may be developed in the mid-term (i.e. within 10 to 20 years), particularly with the rising profile of IPP's (independent power producers).

A number of factors could encourage the development of cogeneration, particularly in the pulp and paper sector of the forest industry. These factors can be divided into four categories: technical, economic and financial, utility policy and government policy.

The principal technical factor favouring cogeneration at a pulp mill is the ability of a cogeneration plant to sequentially supply all of the process heat and all or part of the electricity demand. The process permits the recovery of pulping liquor and in some plants helps to dispose of waste wood and bark. High process steam requirements (greater than 45 000 kg/h), production of steam at high pressure (4130 kPa or more), low process steam pressure (1135 kPa or less), high plant load factor and high reliability encourage cogeneration.[85]

The principal economic benefits which encourage cogeneration are reduced fuel and disposal costs. However, joint utility/cogenerator financing or other financial assistance may be required to remove financial constraints and improve the benefits to the pulp mill in order to produce an economic project. Increasing the plant life to 25 years or more would also improve project economics.

[*1] Includes cogeneration at Howe Sound Pulp and Paper at Port Mellon and wood-fired thermal generation by Northwest Energy at Williams Lake.

Utility policy can encourage the development of cogeneration with long-term, take-or-pay contracts for the surplus power at higher buy-back rates and/or higher electricity rates for industry. Each of these alternatives has risks either from increased electricity prices to other ratepayers and/or reduced industrial growth. A low price for wheeling can be used to encourage cogeneration by providing the potential for higher prices and a higher capacity factor. Cogeneration commonly has a shorter lead time than conventional utility generation which is advantageous in a time of uncertain load growth and thereby provides an advantage to the utility and a justification for a higher price. Governments can encourage cogeneration by providing tax relief, grants or loans to cogenerators. The introduction of investment tax credits and a quick write-off encourages cogeneration. Governments can also affect cogeneration favourably or unfavourably with regulations for interconnection, buy-back and wheeling requirements.

Other factors can encourage the development of cogeneration. In order to maximize overall efficiency a cogeneration system should be base loaded; supplementary heat, electricity or mechanical work may be best supplied by other conventional systems. However, oversizing the prime mover is less critical for steam turbines than for gas turbines where increased stack-gas temperatures in gas turbines would produce unacceptable energy losses.

An Integ study (1980) identified three specific methods for increasing the amount of available cogeneration in the B.C. forest industry:[19]

1. Replacement of existing steam boilers with higher pressure boilers.

2. Replacement of direct steam turbine (mechanical) drives with more efficient electrical drives.

3. Improvement of project economics by replacement of fossil fuel-fired boilers with hog fuel-fired boilers.

Despite these factors which could encourage cogeneration, there are many constraints on the development of additional cogeneration. These constraints can also be divided into technical, financial and economic, utility and government involvement and company attitude.

Technical factors include the following:[19]

1. The balance of thermal and electrical load.

2. The difficulty of retrofitting.

3. For hog fuel-fired plants - the security of a long-term fuel supply, the variable quality and low heating value of the fuel and the restrictions on particulate emissions.

4. Lumber mills are seldom suitable for extraction-condensing power generation because of a low annual load factor and the high cost per kilowatt for small plants.

Advances in pulp mill technology have adversely tipped the balance between thermal and electrical load. The following advances have increased the use of electricity largely by substituting electricity use for steam use:[22]

1. High speed paper machines reduce steam use by increasing press loading.

2. The chemi-thermo-mechanical and thermo-mechanical pulping processes improve wood use and reduce steam use.

3. The operation of fans and pumps for heat recovery systems reduces steam requirements.

4. Steam turbine drives have been replaced with more efficient electrical drives.

Numerous financial and economic constraints which are imposed by cogenerators restrict the development of cogeneration. A high rate of return (more than 20 percent) and a payback of less than 3 years are imposed on investments by the forest companies because of the competitiveness of the national and international marketplaces. The low differential cost of utility-supplied bulk electricity sales (approximately 30 mills/kW·h) relative to cogeneration reduces the incentive to cogenerate. The large capital investment for hog fuel-fired plants and the recent volatility in natural gas and oil prices deter their use in cogeneration. Lastly, privately-owned forest companies rely on internal equity funding for capital projects rather than relying on debt financing.

Other utility policies such as low buy-back rates adversely affect the development of cogeneration. Utilities are often reluctant to encourage cogeneration because of the uncertainties that can be introduced into load forecasting, generation planning, fuel planning and system operation. Increased cogeneration can reduce demand from industrial customers and contribute to surplus generation and transmission capacity. Utilities with surplus power and energy have no desire to purchase additional electricity. They are concerned about the potential loss of load and revenue because of the development of new cogeneration in their service areas. The location of new cogeneration can be an operational concern depending on its reliability and size which can affect utilization by the utility. A large cogenerator could adversely affect power quality and safety on the transmission or distribution system. In some cases, the use of fuel and the mutually exclusive demands on the air shed by a cogenerator could have an impact on a thermally dependent utility.

Government involvement in such matters as licencing, regulation and environmental protection does not usually constrain cogeneration. However, government incentives such as the Class 34 capital cost allowance on cogeneration equipment or an equivalent designation (Class 29) promotes cogeneration and the removal of this incentive would adversely affect its economics.

Company attitudes and other company-related factors have an impact on developing cogeneration. Industrial firms are often unwilling to become involved in new fields such as self-generation and particularly the sale of electricity. They want to invest their profits in increasing the production of their primary product. In addition, boilers are expected to last 30 years or more before replacement which reduces the opportunity for installing high pressure boilers to increase electricity production at existing cogeneration plants.[1] Company-related factors which affect the reliability of cogenerated electricity include the following:[86]

1. Interruptions by strikes at the mills or in the woods, forest closures because of fire hazards or decreased markets for pulp and/or paper.

2. Interruptions caused by forest company policy beyond the control of the utility.

The factors cited in Item 1 would also reduce the demand for electricity, so the reduced demand would partly compensate for the loss of cogenerated electricity. Interruptions because of policy decisions by the forest companies would be unpredictable and reduce the utility's ability to optimize its generation. Companies may stress that reliability should be judged on the basis of all cogenerators on the utility's transmission/distribution system taken as a group and not on the basis of one cogeneration plant considered in isolation and this is a factor which the utility should consider. In addition to the constraints, utilities have technical requirements for parallel generation of electricity. These requirements ensure that the safety and reliability of the utility system is not adversely affected by the cogenerator. The B.C. Hydro requirements are as follows:[2]

1. A means of synchronizing the generator and the power system.

2. A circuit breaker between the generator and the power system, with adequate interrupting capacity to clear all faults on either side of the breaker.

3. Generator overload protection.

4. Provision for automatic disconnection of the generator from the power system in the event of an outage of the power system supply.

5. An electrical supply within utility standards and provision for isolation of the generator from the power system in the event of unsatisfactory generator voltage or frequency.

6. A visible, manual, lockable disconnect switch close to the point of interconnection of the generator and the power system; this provides utility maintenance crews with a means of isolating the generator when work on power system equipment is necessary.

7. All equipment must be CSA and B.C. Hydro approved and installed in accordance with the Electricity Safety Code.

8. All equipment must be designed to avoid damage from over-voltage or automatic reclosure operations on the power system.

9. The harmonic content of the generator output must be within acceptable limits.

10. Equipment for remote tripping of the cogenerator's equipment may be required.

11. "In-out" meters will be supplied by the cogenerator to measure power flows to and from the B.C. Hydro system.

The association of B.C. utilities with cogeneration facilities is a long one. Consideration of cogeneration by B.C. utilities began in 1959 when B.C. Electric evaluated the construction of a 150 MW hog fuel-fired boiler at Burrard Thermal Generating Station. Cogeneration is now commonplace in the B.C. pulp and paper industry. Over 90 percent of the cogeneration facilities in B.C. are in the pulp, paper and lumber mill segments of the forest industry. The remaining process steam users, some with generation, are in petroleum refineries, hospitals, a district/central heating plant, a sugar refinery, distillery and a natural gas processing and transmission operation.[19]

Approximately 50 percent of the process steam produced by non-forest product industries is at pressures below 1240 kPa (180 psi).[19] However, the Gulf Oil refinery in Port Moody produces steam at 4240 kPa (600 psig) and Westcoast Transmission, at its Fort Nelson natural gas processing and transmission plant, produces steam at 3205 kPa (450 psig). The Westcoast plant provides its own mechanical and electrical power.

Natural gas and oil are used for steam generation at most of the non-forest industry plants. The four B.C. petroleum refineries are exceptions; these plants use off-gas from their processes to supplement the primary fuels.

Cogenerated electrical power consists of 8 MW in total at Westcoast Transmission and the B.C. Sugar Refining Company.[71] The Vancouver General Hospital is equipped with 1.3 MW of generating capacity which only operates on a standby basis. Westcoast Energy at Fort Nelson could generate another 30 to 100 MW and the refineries and chemical plants another 80 MW.

The appropriate prime mover and unit size for a cogeneration system depend on the thermal/electrical output ratio and the available fuel type(s). Prime movers include steam boilers, gas turbines and diesel engines.

Steam turbines are favoured for cogeneration because they can effectively track varying steam demands with smaller losses in fuel efficiency than either gas turbines or diesels. Any excursion from the design point of any system tends to decrease fuel efficiency. However, with steam turbines there is typically a loss in efficiency of only 10 percent at 50 percent load.

Steam turbines tend to use a topping cycle rather than a bottoming cycle because the process use generally requires only low-grade steam. The topping cycle must be capable of changing its power-to-heat ratio to suit steam demand. However, sizing is important, although it is difficult to optimize in situations where steam demands vary because of variations in process steam requirements and weather-dependent non-process loads. For this reason, load duration curves (process steam consumption and electricity load vs. time) are good tools for estimating the performance of cogeneration units.

Popular fuels for cogeneration in the B.C. forest industry include hog fuel, black liquor, fuel oil, natural gas and residual oil. There is considerable potential for cogeneration where there are sources of natural gas, coal and surplus hog fuel.

Although it is an added complication, hog fuel dryers can significantly improve the efficiency of hog fuel-fired plants. Various types of prime movers can be used depending on the moisture content of the hog fuel and the amount of steam required. Steam turbines are the most common, but steam engines are more economical at low steam pressures and for generation of less than 2 MW. Gasification of wood waste can produce a gaseous fuel, but gas clean-up tends to be troublesome and the low heating value of the fuel significantly reduces performance in both reciprocating engines and gas turbines.

Sawmills provide most of the hog fuel used by the pulp and paper industry. The alternatives to disposal of wood waste (hog fuel) with steam production are incineration and landfilling, but neither of these alternatives is satisfactory. The hog fuel is used in hog fuel boilers to provide steam for "cooking" the pulp and electricity for chipping, mixing, etc. Chemical pulping tends to use a large amount of process steam as well as electricity, whereas mechanical, thermo-mechanical (TMP) and chemi-thermo-mechanical (CTMP) pulping tend to use more electricity. However, thermo-mechanical and chemi-thermo-mechanical pulping make more effective use of the wood resource. Kraft mills dominate in the B.C. pulp industry, but TMP and CTMP mills are popular for new facilities.

Environmental impacts from cogeneration systems include air emissions, water contamination, fogging, fisheries losses, reduction of wildlife habitat, other land use conflicts, visual impacts, noise and socio-economic impacts. However, the improved efficiency and control of burning during cogeneration may actually reduce overall environmental impacts.

The decision to develop cogeneration at an industrial site is ultimately an economic one. The following variables will affect that decision:

1. The quantities of electricity and/or fuel displaced.
2. The cost of the electricity and/or fuel displaced (dependent on fuel type and long-term value of electricity at 36.2 mills/kW·h).*1
3. The escalation rate of future energy (fuel and electricity).

NOTE: *1 D. F. Gillespie. 1987. B.C. Hydro Memorandum to Transmission Planners dated 2 October 1987.

4. The potential for the sale of surplus power and the selling price.

5. Debt/equity ratio.

6. Interest rate and return on equity (11 to 12 percent after taxes for private industry).

7. Term of debt (commonly 3 years).

8. General inflation rate (approximately 5 percent).

9. Capital cost of plant modifications.

10. Project life (25 years).

11. Total federal and provincial taxation rate (approximately 46 percent).

12. Depreciation rate (assume Class 34 depreciation of 25 percent in the first and third years and 50 percent in the second year on special equipment if the heat rate is higher than 7384 kJ/kg; buildings are subject to Class 6 depreciation).

The principal economic analysis in this report is based on the above criteria and focused on pulp and paper mills because of their present cogeneration and their potential for expansion. The economic analysis used simple payback, internal rate of return and unit energy cost to evaluate the incremental cost of steam production and electrical generation.

In conducting the economic analysis six alternatives were evaluated because of the lack of information on cogeneration costs for specific pulp mills:

1. Removal of pressure reducing valves (PRV's) only.

2. Removal of PRV's and some mechanical drives.

3. Addition of small, medium and extensive modifications which affect capital cost.

4. Various hog fuel costs with and without supplementary fuel.

5. Various electricity prices.

6. Various boiler pressures which affect the electricity generation.

Summaries of simple paybacks after tax which are less than 3 years are summarized in Tables 14-1 through 14-3. Hog fuel costs are assumed to range from $0.58/GJ to $1.38/GJ. Capital costs are affected by the cost of replacement of PRV's, mechanical drives and outdated equipment which in turn affects the amount of electrical generation expected. Therefore, payback is more sensitive to changes in capital cost than it is to changes in fuel cost. The paybacks are under 3 years, only for low to medium capital cost projects. The addition of a supplementary fuel has little impact on the economics of cogeneration. In terms of simple payback, there is a distinct advantage in changing from 4240 kPa/400°C to 6310 kPa/445°C,

TABLE 14-1

Simple Payback After Tax
Steam Pressure: 4240 kPa, Temperature: 400°C

Hog Fuel Cost* ($/GJ)	Steam Cost ($/GJ)	Electricity Price (mills/kW·h)	Payback (Years)	Capital Cost (k$)	Electrical Generation (GW·h/a)	Replacement		Type of Supplementary Fuel
						PRV	PRV & Mechanical Drives	
0.58	0.89	40	2.7	6,955	84.9	✓		Nil
0.71	1.09	40	2.7	6,955	84.9	✓		Nil
1.04	1.60	40	2.9	6,955	84.9	✓		Nil
0.58	0.89	40	2.3	10,122	146.2		✓	Nil
0.71	1.09	40	2.4	10,122	146.2		✓	Nil
1.04	1.60	40	2.5	10,122	146.2		✓	Nil
1.38	2.12	40	2.6	10,122	146.2		✓	Nil
0.58	0.89	35	2.6	10,122	146.2		✓	Nil
0.71	1.09	35	2.6	10,122	146.2		✓	Nil
1.04	1.60	35	2.8	10,122	146.2		✓	Nil
0.58	1.41	40	2.8	6,955	84.9	✓		Oil
0.71	1.25	40	2.8	6,955	84.9	✓		Natural Gas
1.04	1.68	40	2.9	6,955	84.9	✓		Natural Gas
0.58	1.41	40	2.4	10,122	146.2		✓	Oil
0.71	1.25	40	2.4	10,122	146.2		✓	Natural Gas
1.04	1.68	40	2.5	10,122	146.2		✓	Natural Gas
1.38	2.45	40	2.7	10,122	146.2		✓	Oil
0.58	1.41	35	2.7	10,122	146.2		✓	Oil
0.71	1.25	35	2.7	10,122	146.2		✓	Natural Gas
1.04	1.68	35	2.8	10,122	146.2		✓	Natural Gas

* Includes a credit of $0.31/GJ (Coast) or $0.32/GJ (Interior) for reduced disposal cost.

TABLE 14-2

Simple Payback After Tax
Steam Pressure: 6310 kPa, Temperature: 445°C

Hog Fuel Cost* ($/GJ)	Steam Cost ($/GJ)	Electricity Price (mills/kW·h)	Payback (Years)	Capital Cost (k$)	Electrical Generation (GW·h/a)	Replacement		Type of Supplementary Fuel
						PRV	PRV & Mechanical Drives	
0.58	0.89	40	2.5	9,829	127.9	✓		Nil
0.71	1.09	40	2.6	9,829	127.9	✓		Nil
1.04	1.60	40	2.7	9,829	127.9	✓		Nil
1.38	2.12	40	2.9	9,829	127.9	✓		Nil
0.58	0.89	35	2.8	9,829	127.9	✓		Nil
0.71	1.09	35	2.9	9,829	127.9	✓		Nil
0.58	0.89	40	2.2	12,516	190.9		✓	Nil
0.71	1.09	40	2.3	12,516	190.9		✓	Nil
1.04	1.60	40	2.4	12,516	190.9		✓	Nil
1.38	2.12	40	2.5	12,516	190.9		✓	Nil
0.58	0.89	35	2.5	12,516	190.9		✓	Nil
0.71	1.09	35	2.6	12,516	190.9		✓	Nil
1.04	1.60	35	2.7	12,516	190.9		✓	Nil
1.38	2.12	35	2.9	12,516	190.9		✓	Nil
0.58	0.89	30	2.8	12,516	190.9		✓	Nil
0.71	1.09	30	2.9	12,516	190.9		✓	Nil
0.58	1.41	40	2.7	9,829	127.9	✓		Oil
0.71	1.25	40	2.6	9,829	127.9	✓		Natural Gas
1.04	1.68	40	2.7	9,829	127.9	✓		Natural Gas
0.71	1.25	35	2.9	9,829	127.9	✓		Natural Gas
0.58	1.41	40	2.3	12,516	190.9		✓	Oil
0.71	1.25	40	2.3	12,516	190.9		✓	Natural Gas
1.04	1.68	40	2.4	12,516	190.9		✓	Natural Gas
1.38	2.45	40	2.6	12,516	190.9		✓	Oil
0.58	1.41	35	2.6	12,516	190.9		✓	Oil
0.71	1.25	35	2.6	12,516	190.9		✓	Natural Gas
1.04	1.68	35	2.7	12,516	190.9		✓	Natural Gas
0.71	1.25	30	2.9	12,516	190.9		✓	Natural Gas

* Includes a credit of $0.31/GJ (Coast) or $0.32/GJ (Interior) for reduced disposal cost.

TABLE 14-3

Simple Payback After Tax
Steam Pressure: 8720 kPa, Temperature: 480°C

Hog Fuel Cost* ($/GJ)	Steam Cost ($/GJ)	Electricity Price (mills/kW·h)	Payback (Years)	Capital Cost (k$)	Electrical Generation (GW·h/a)	Replacement PRV	Replacement PRV & Mechanical Drives	Type of Supplementary Fuel
0.58	0.89	40	2.6	13,214	165.9	✓		Nil
0.71	1.09	40	2.6	13,214	165.9	✓		Nil
1.04	1.60	40	2.8	13,214	165.9	✓		Nil
1.38	2.12	40	2.9	13,214	165.9	✓		Nil
0.58	0.89	35	2.9	13,214	165.9	✓		Nil
0.71	1.09	35	2.9	13,214	165.9	✓		Nil
0.58	0.89	40	2.5	17,335	230.3		✓	Nil
0.71	1.09	40	2.5	17,335	230.3		✓	Nil
1.04	1.60	40	2.6	17,335	230.3		✓	Nil
1.38	2.12	40	2.7	17,335	230.3		✓	Nil
0.58	0.89	35	2.7	17,335	230.3		✓	Nil
0.71	1.09	35	2.8	17,335	230.3		✓	Nil
1.04	1.60	35	2.9	17,335	230.3		✓	Nil
0.58**	1.41	40	2.7	13,214	165.9	✓		Oil
0.71**	1.25	40	2.7	13,214	165.9	✓		Natural Gas
0.58**	1.41	40	2.5	17,335	230.3		✓	Oil
0.71**	1.25	40	2.6	17,335	230.3		✓	Natural Gas
0.58**	1.41	35	2.8	17,335	230.3		✓	Oil
0.71**	1.25	35	2.9	17,335	230.3		✓	Natural Gas

* Includes a credit of $0.31/GJ (Coast) or $0.32/GJ (Interior) for reduced disposal cost.

** Only a few representative fuel costs were estimated.

but little advantage in changing from 6310 kPa/445°C to 8720 kPa/480°C because of the increases in capital costs with increases in boiler pressure/temperature. However, the internal rates of return are distinctly higher at higher pressures and temperatures. This apparent anomaly is caused by the use of the Class 34 depreciation.

At a 5 percent discount rate, only the most capital intensive projects or projects with high fuel prices are uneconomic compared with B.C. Hydro's long-term marginal cost of electricity. Therefore, there is an opportunity to negotiate with the pulp and paper industry to encourage cogeneration projects with projected internal rates of return above a 20 percent hurdle rate, but below B.C. Hydro's long-term marginal cost of energy. There is also potential for developing cogeneration or condensing wood-fired thermal power generation for export where high purchase prices warrant development.

In pulp mills, steam is commonly produced in both power boilers and recovery boilers. The pressure of boiler steam for the process in pulp mills is reduced by employing mechanical drive backpressure turbines, extraction/backpressure generator drive turbines and/or pressure reducing valves. Extraction/backpressure generator drive turbines are the most efficient and should be promoted to encourage the efficient use of the wood resource.

Cogeneration could be used in industries other than the pulp and paper sector of the forest industry. However, in most industries the heat/electricity ratio or the seasonal nature of the heat and/or electricity load make the adoption of cogeneration impractical or uneconomic. One potential method of avoiding this problem is to combine industries with complementary high heat or steam loads with industries with medium to high electric loads or alternately sell surplus electricity to the utility. Industries with high heat loads include food processing, paper, chemical, petroleum and stone and clay.

Gas turbine or gas turbine combined cycle power plants could be economical in supplying heat and electricity to food processing or chemical plants. Some applications may be found by putting an electricity-intensive industry adjacent to a heat or steam-intensive industry in the same industrial park.

Emissions are the most important environmental concern with cogeneration plants. These emissions include oxides of nitrogen, sulphur dioxide, carbon dioxide/carbon monoxide, hydrocarbons, particulates and trace elements. The importance of individual emissions depends on the fuel type and the technology being used. Wood fuel and pulping liquor are the most popular fuels in the B.C. cogeneration industry and future additions are likely to use more wood fuel. The principal emissions from the combustion of wood fuel are oxides of nitrogen, carbon dioxide/carbon monoxide and particulates. Control technologies can significantly reduce the emissions of oxides of nitrogen and particulates. Removal of particulates could improve local air quality where wood waste is currently incinerated in bee hive burners. However, there is presently no effective method for controlling carbon dioxide/carbon monoxide emissions.

The principal opportunity for cogeneration in B.C. continues to be in the forest industry. However, the opportunity in the pulp sector is decreasing with the use of TMP and CTMP technologies. Therefore, opportunities should also be sought in other industries.

SECTION 15.0 - CONCLUSIONS

There is some potential for additional cogeneration in the B.C. pulp and paper industry. The potential is limited by the availability of inexpensive fuels, the potential for escalation in fuel prices and the availability of candidate sites with PRVs, mechanical drives or old boilers which could be replaced. Alternatively, new pulp mills which could design extensive cogeneration into their proposed plant could benefit significantly from cogeneration, particularly in areas of the B.C. Interior where there are extensive hog fuel surpluses.

Other industries could also benefit from cogeneration where there is a high heat or steam load and where the electricity which is generated could be used within the plant, by an adjacent plant or sold to B.C. Hydro. These situations are most applicable in industrial parks where industries are relatively close together. Chemical plants, coal drying facilities and natural gas pumping or processing plants are also potential sites.

Cogeneration is often unattractive because of the high hurdle rates or short paybacks used by industry. Utilities traditionally use much lower hurdle rates or longer paybacks which could allow room for negotiation and encourage cogeneration. B.C. Hydro is presently negotiating with several potential cogenerators, particularly in the pulp and paper industry, to increase their self-generation and possibly sell electricity to B.C. Hydro. This generation could defer new, large hydroelectric generation and reduce generation costs to B.C. Hydro while providing an adequate profit to the cogenerator. Contracts have been negotiated with Howe Sound Pulp and Paper (a cogenerator) and North West Energy (an independent power producer), and others are expected to follow.

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APPENDICES

APPENDICES

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APPENDIX A - GLOSSARY

Biomass - Any form of organic material used in combustion, exclusive of fossil fuels, but including wood, bark, sugar cane, corn husks/etc.

Black Liquor - A mixture of spent chemicals, lignin and water which is produced during the kraft process.

Bottoming Cycle - A thermal cycle in which thermal energy is produced for process use and waste heat is recovered for generating electricity.

Capacity Factor - The average power output of a system divided by its rated power output.

Cogeneration - The sequential production of mechanical or electrical energy and useful thermal energy in the form of steam or hot water from a single energy (fuel) source.

Enthalpy - Enthalpy is technically the sum of the internal energy and the product of its pressure and temperature. However, in combustion reactions it is effectively the exothermic heat of the reaction at constant pressure and corresponds to the higher heating value of the fuel.

Forest Residue - Unprocessed wood waste which remains in the forest after conventional logging is completed.

Hog Fuel - A combination of bark, wood chips and/or sawdust that has been comminuted through a hog or chipper to a size that permits pile burning in a furnace.

Isentropic - At constant entropy where entropy is a measure of the scope of a material for changing its internal arrangement or the change in heat content at constant temperature.

Load Factor - The ratio of the average load during a given period to the peak load during the same period.

Pyrolysis - A process of conversion of coal to gaseous and liquid products plus a char. The process requires high to medium temperature and insufficient air to permit combustion.

Self-Generation - Generation where the customer generates his own electric power, possibly with the sale of surplus power to a utility.

Topping Cycle - A thermal cycle in which electricity or mechanical energy is extracted first and the exhaust steam is delivered as thermal energy or some other form of useful work.

APPENDIX B - SUMMARY OF CONSTANTS AND EQUIVALENT BRITISH/METRIC UNITS

2204 lb = 1 tonne
1 unit (average hog fuel) = 2000 lb (dry) approx. = 907 kg
1 unit (average hog fuel) = 4000 lb (@ 50% moisture) approx. = 1814 kg
1 bone dry unit = 2400 lb (dry) = 1088 kg
1 barrel = 42 gallons (U.S.) = 32 gallons (Cdn.) = 0.159 m^3 = 159 L
1 gallon (Imperial) = 4.54 L
1 gallon (U.S.) = 3.79 L
1 mcf (thousand ft^3) = 28.32 m^3 = 28320 L
1 psia = 6.895 kPa
1 horsepower = 0.746 kW
1 board foot = 1/12 ft^3 = 0.00236 m^3
1 cunit = 100 ft^3 (solid) = 2.832 m^3 (solid)
1 cord = 128 ft^3 (bulk) = 3.625 m^3 (bulk)
1 cord = 75 to 90 ft^3 (solid) = 2.124 m^3 to 2.549 m^3 (solid)
1 Btu = 1.05506 kJ
1 Btu/lb = 2.326 kJ/kg
3413 Btu = 1 kW·h = 3600 kJ

Combustion Efficiency of oil-fired boilers (%)	85
Combustion Efficiency of gas-fired boilers (%)	82
Combustion Efficiency of wood-fired boilers (%)	60-72

Heating Values:	Natural gas	37.31 GJ/10^{3}m^3
	Light fuel oil	38.18 MJ/L
	Heavy fuel oil	41.73 MJ/L
	Liquid petroleum gas (LPG)	26.56 MJ/L
	Pulping (black) liquor	14.89 MJ/kg
	Municipal solid waste (MSW)	10.47 MJ/kg
	Electricity	3.6 MJ/kW·h

Physical Constraints and Approximations:

Specific Heat Capacity of Water (constant pressure)	4.19 kJ/L/°C
Specific Heat Capacity of Steam (constant pressure)	2.10 kJ/L/°C
Heat of Vaporisation of Water	2442 kJ/kg
Steam Requirement at 1250 psi (8620 kPa)	7.576 kg/kW·h[*1]
Steam Requirement at 650 psi (4480 kPa)	11.364 kg/kW·h[*1]
Efficiency of a non-condensing turbine	4.22 MJ/kW·h
Quantity of steam that can be produced from a unit of black liquor (kg/kg)	2.636

NOTE: [*1] Assumes 80 percent hog fuel and 20 percent oil fuel; the latter for flame stability.

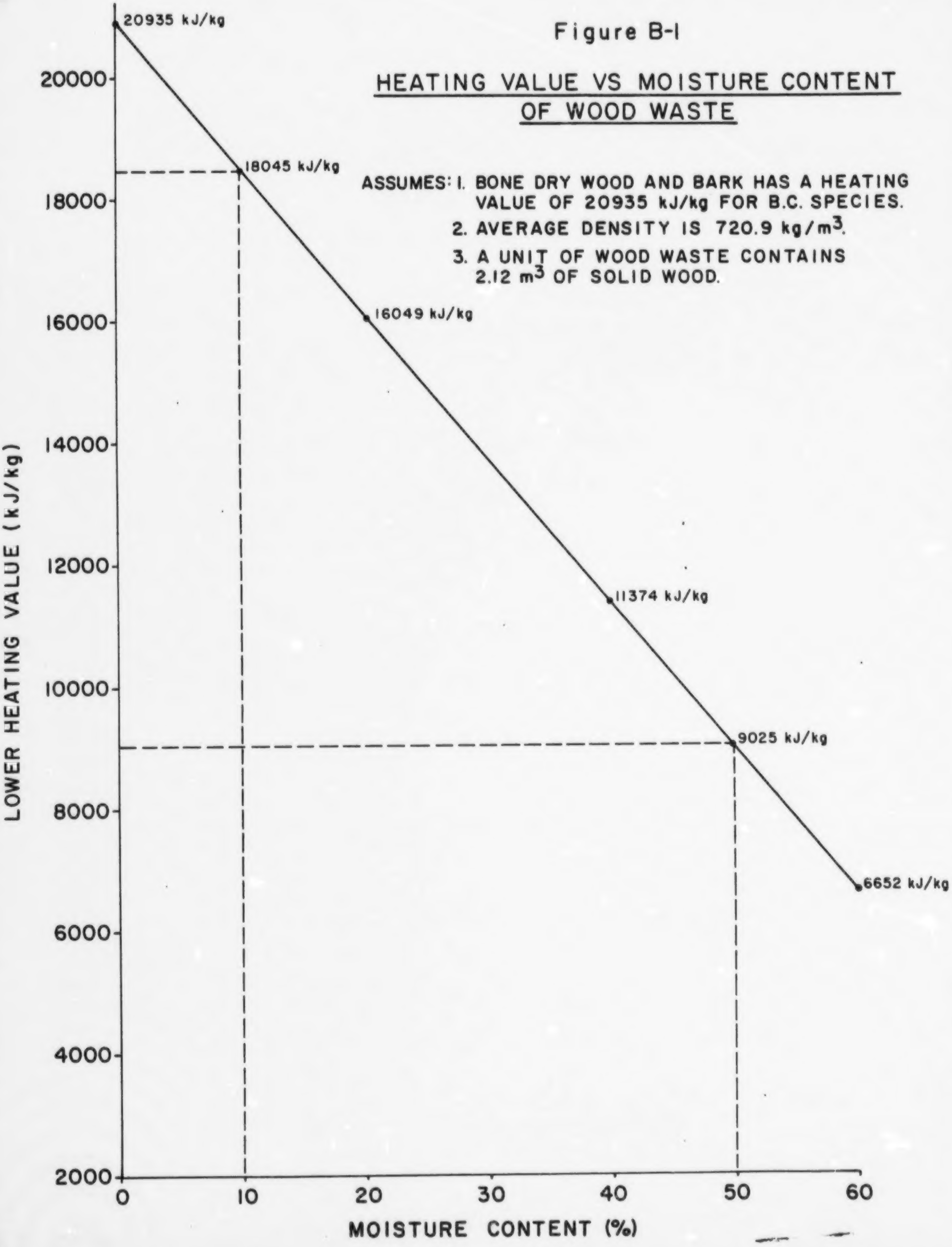

Figure B-1

HEATING VALUE VS MOISTURE CONTENT OF WOOD WASTE

ASSUMES: 1. BONE DRY WOOD AND BARK HAS A HEATING VALUE OF 20935 kJ/kg FOR B.C. SPECIES.

2. AVERAGE DENSITY IS 720.9 kg/m^3.

3. A UNIT OF WOOD WASTE CONTAINS 2.12 m^3 OF SOLID WOOD.

APPENDIX C - PARAMETERS FOR ESTIMATES OF UNIT ENERGY COSTS

Unit energy costs were estimated for several capital costs and fuel costs at five and ten percent interest rates in order to evaluate the sensitivity to these parameters. For simplicity, construction time was assumed to be one year and interest during construction was not included. In addition, the contingency allowance and corporate overhead were assumed to be included in the construction cost. The project life was taken as 25 years. The firm energy is net of any station service or transmission losses in transferring power to the B.C. Hydro system. Fuel costs include delivery and processing charges. Fixed operation and maintenance costs were estimated as a percentage of the construction costs including engineering.